Massachusetts Electric
A National Grid Company

November 21, 2003

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Exogenous Factor Filing

Dear Secretary Cottrell:

Pursuant to Section I.C.1 of the Rate Plan Settlement ("Rate Settlement") in D.T.E. 99-47, Massachusetts Electric Company and Nantucket Electric Company (collectively "Company") hereby propose a distribution rate change for calendar year 2004 for exogenous events occurring after the date of the Rate Settlement. As set forth in this filing, the Company requests an Exogenous Factor ("Factor") of 0.014¢ per kWh effective for usage on and after January 1, 2004.

Under the Rate Settlement, the Company has the right to file for a distribution rate change as a result of the following events: (1) tax and accounting changes which, individually, would affect Mass. Electric's costs by more than $1 million annually (§I.C.1.a); (2) legislative or regulatory changes that would impose new or modify existing obligations or duties on the Company which, individually, affect the Company's costs by more than $1 million annually (§I.C.1.b); and (3) the reclassification of costs to, or away from, transmission or generation from, or to, distribution (§I.C.1.d). The Rate Settlement provides for an annual filing of exogenous factors, to the extent that they may exceed the annual thresholds established under the Rate Settlement, by December 1 of each year, to become effective for usage on and after January 1 of the following calendar year. Exogenous factors are to be applied to all kWh billed by the Company through a uniform, fully reconciling surcharge or credit factor. Any request for an exogenous factor is also subject to review and approval by the Department. See §I.C.2 of Rate Settlement.

The exogenous events total approximately $3.1 million. They include a credit to customers of approximately $2.1 million relating to the effect of a change in tax depreciation rules (bonus depreciation), offset by recovery of approximately $3.4 million associated with regulatory rule changes (Renewable Portfolio Standards compliance and Standard Offer Service costs incurred as a result of Standard Market Design) and recovery of approximately $1.8 million associated with a reclassification of costs from transmission to distribution (congestion costs).

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This filing consists of the prefiled testimony of Theresa M. Burns, Michael D. Laflamme, and Michael J. Hager. Ms. Burns presents the basis for recovery of each of the components as exogenous factors under the Rate Settlement. Mr. Laflamme presents the tax depreciation rule changes, and Mr. Hager presents the other cost components.

Thank you very much for your time and attention to this filing.

Very truly yours,

Thomas. G. Robinson
Amy G. Rabinowitz

cc: Joseph Rogers, Office of the Attorney General

Massachusetts Electric Company
And
Nantucket Electric Company

Exogenous Factor Filing

Testimony and Exhibits of:

Theresa M. Burns,
Michael D. Laflamme, and
Michael H. Hager

November 21, 2003

Submitted to:
Department of Telecommunications and Energy
Docket No. DTE ______

Submitted by:

Massachusetts Electric
A National Grid Company

Nantucket Electric
A National Grid Company

DIRECT TESTIMONY

OF

THERESA M. BURNS

Table of Contents

I. Introduction and Qualifications

Q. Please state your full name and business address.

A. My name is Theresa M. Burns, and my principal place of business is 55 Bearfoot Road, Northborough, Massachusetts 01532.

Q. Please state your position.

A. I am Manager of Distribution Rates-New England for National Grid USA Service Company, Inc., performing rate related services for companies of National Grid USA, including Massachusetts Electric Company ("Mass. Electric") and Nantucket Electric Company ("Nantucket") (together "the Company").

Q. Please describe your educational background and training.

A. I graduated from Babson College in Wellesley, Massachusetts with a Bachelor of Science degree in Accounting in 1986. In 1994, I received a Masters in Business Administration from Babson College. I am a certified public accountant and a member of the Massachusetts Society of Certified Public Accountants.

Q. Please describe your professional experience.

A. From 1986 to 1990, I was an auditor for Ernst & Young in Boston, Massachusetts. In June 1990, I joined New England Power Service Company ("NEPSCO") as an Accounting Analyst in the Financial Analysis Group of the General Accounting Department. In June

1991, I was given responsibility over general ledger accounting for NEPSCO's three retail affiliates. In July 1993, I joined the Internal Audit Department and was responsible for performing both financial and operational audits. In June 1994, I was promoted to Senior Internal Auditor. In July 1995, I transferred to the Rate Department as a Senior Rate Analyst. In this position, I have been responsible for the design and implementation of retail access rates. In April 1999, I was promoted to Principal Rate Analyst. Upon the merger of Eastern Utilities Associates with National Grid USA, I was renamed Principal Financial Analyst. In October 2000 I was promoted to Manager of Distribution Rates.

Q. Have you previously testified before the Department of Telecommunications and Energy ("the Department")?

A. Yes I have.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Company's proposed Exogenous Factor ("Factor") for calendar year 2004. The Company is requesting a Factor of 0.014¢ per kWh and is proposing that the Factor become effective for usage on and after January 1, 2004. The proposed Factor is calculated in Exhibit TMB-1.

Q. Under what mechanism is the Company making this filing?

A. The terms of the Company's November 29, 1999 Rate Plan Settlement ("Rate Settlement") in Docket No. D.T.E. 99-47 regarding its merger with Eastern Edison Company provides the Company the ability to adjust its distribution rates in connection with exogenous factors occurring after the date of the Rate Settlement. See §I.C.1 of Rate Settlement. Pursuant to §I.C.1, the Company has the right to file for a distribution rate change as a result of the following events: (1) tax and accounting changes which, individually, would affect Mass. Electric's costs by more than $1 million annually (§I.C.1.a); (2) legislative or regulatory changes that would impose new or modify existing obligations or duties on the Company which, individually, affect the Company's costs by more than $1 million annually (§I.C.1.b); and (3) the reclassification of costs to, or away from, transmission or generation from, or to, distribution (§I.C.1.d).

The Rate Settlement provides for an annual filing of exogenous factors, to the extent that they may exceed the annual thresholds established under the Rate Settlement, by December 1 of each year, to become effective for usage on and after January 1 of the following calendar year. Exogenous factors are to be applied to all kWhs billed by the Company through a uniform, fully reconciling surcharge or credit factor. Any request for an exogenous factor is also subject to review and approval by the Department. See §I.C.2 of Rate Settlement. The Company has chosen the period ending December 31 as the measurement period for the tax-related exogenous factor due to the nature of accounting for deferred income taxes. The Company has chosen the period ending September 30 as the measurement period for the remaining exogenous factors proposed in this filing to coincide with the period associated with its other reconciling factors that are typically filed by December 1 of each year for rates to become effective January 1 of the following year.

The Company has summarized the exogenous factors it has included in this filing which are used to design the proposed Factor. Exhibit TMB-2 presents a summary of these items, which total approximately $3.1 million. This total is comprised of a credit to customers of approximately $2.1 million relating to the effect of a change in tax depreciation rules (bonus depreciation), offset by recovery of approximately $3.4 million associated with regulatory rule changes (Renewable Portfolio Standards compliance and Standard Offer Service costs incurred as a result of Standard Market Design) and recovery of approximately $1.8 million associated with a reclassification of costs from transmission to distribution (congestion costs).

Q. What costs is the Factor intended to recover?

A. The Company is proposing the Factor in order to reflect changes in costs pursuant to the exogenous factor provision. These changes represent both a decrease in the Company's revenue requirement related to a change in tax rules combined with increased costs resulting from regulatory rule changes and reclassification of costs. The Factor is intended to pass on to customers the benefit associated with the bonus depreciation tax rules, enacted in 2002. The Factor also provides for recovery from customers of costs associated with the

Company's obligation under the Department of Energy Resources' ("DOER") new Renewable Portfolio Standards ("RPS") regulations and recovery of costs that have been reclassified from transmission as the result of the Independent System Operator-New England's ("ISO-NE") Standard Market Design ("SMD") filing with the Federal Energy Regulatory Commission ("FERC"), which became effective on March 1, 2003.

Q. How is the Company's filing structured?

A. My testimony presents the basis for recovery of each of the components as exogenous factors under the Rate Settlement. Also provided as part of this filing is the testimony of Mr. Michael D. Laflamme, Manager of Regulatory Support, New England and the testimony of Mr. Michael J. Hager, Vice President of Energy Supply, New England. Mr. Laflamme will discuss the background and impact related to the recently enacted bonus depreciation rules of IRC §168(k) associated with qualifying capital additions for the period September 11, 2001 through September 10, 2004. Mr. Hager will provide the background to and quantify each of the other cost components addressed in this filing. Mr. Hager will describe how new rules associated with RPS, as well as new or changed market rules, which control Mass. Electric's procurement of its Standard Offer Service energy supply, have resulted in the Company incurring new costs or costs that have been reclassified from transmission to distribution, leading to an exogenous factor adjustment provided for under the Rate Settlement.

III. <u>Exogenous Factor Resulting from Tax Change</u>

<u>Bonus Depreciation</u>

Q. Please describe how the change in tax law associated with the allowance for bonus depreciation qualifies as an exogenous factor.

A. As discussed in detail by Mr. Laflamme in his testimony, the increase in the first-year allowable tax depreciation for qualified utility plant placed in service during the period September 11, 2001 and September 10, 2004 has the effect of reducing the Company's rate base, through its effect on accumulated deferred income taxes. The Company's current distribution rates were designed to recover a specified return on rate base. Although technically return on rate base is not an expense in the Company's cost of service (also known as its revenue requirement), the Company believes that the intent of the Rate Settlement provision governing tax and accounting changes resulting in an exogenous factor was to include changes in tax laws which not only would affect the Company's costs, but also its overall cost of service, or revenue requirement. See Rate Settlement, §I.C.1.a. Because the bonus depreciation impact on the Company's rate base and consequently its return aggregates approximately $2.1 million for calendar year 2003, as explained by Mr. Laflamme, which exceeds the $1 million annual threshold required by §I.C.1.a for an exogenous factor associated with tax and accounting changes, the Company is proposing to include this 2003 annual amount of approximately $2.1 million as a credit against the other exogenous factors included in this filing in determining the Factor proposed herein.

IV. Exogenous Factors Resulting from Regulatory Rule Changes

Q. Please describe in more detail the types of costs the Company has been incurring as a result of the new market rules mentioned above.

A. The Company has begun incurring two categories of costs relating to the implementation of new rules relating to its obligation to provide Standard Offer Service, as described by Mr. Hager. This instant filing requests recovery of those costs which are related to the costs incurred for the provision of Standard Offer Service, as described by Mr. Hager in his testimony. For the 12-month period ending September 2003, the Company has incurred approximately $3.4 million of costs related to regulatory rule changes. This amount is comprised of approximately $2.2 million of RPS compliance costs and $1.1 in ISO-NE costs associated with the implementation of SMD, as shown in Exhibit TMB-2.

Renewable Portfolio Standards ("RPS")

First, the Company's provider-of-last-resort load (i.e., Standard Offer and Default Service) is subject to the state's RPS requirements. Compliance costs associated with these RPS requirements consist of the cost of purchasing renewable energy certificates ("RECs"), including any related sales commissions, the costs of making alternative compliance payments ("ACP"), and the assessment by ISO-NE of costs associated with the development and operation of the New England Generation Information System ("GIS").

While the RPS compliance costs described above all arise out of the implementation of new regulatory requirements, the Department has previously ruled that a portion of those costs, i.e., the cost of procuring RECs associated with the Company's Default Service load, should be reflected directly in the Default Service rates charged to Default Service customers. Since November 2002, the Company has included and the Department has approved in its Default Service rates an estimate of the procurement cost of RECs, and therefore the Department has allowed Mass. Electric to recover the cost of RECs in its Default Service rates. Because the recovery of REC costs for Default Service is provided for directly in Default Service rates,[1] the Company is not seeking recovery of those particular costs as part of this exogenous factor filing. However, recovery of the cost associated with the purchase of RECs attributable to the Company's Standard Offer Service load has not been addressed.

In its November 1, 2002 Renewable Energy Portfolio Compliance Plan ("Compliance Plan"), filed in Docket Nos. D.T.E. 99-60 and D.T.E. 00-67 and as explained in more detail by Mr. Hager, the Company stated that it would comply with the RPS requirements by purchasing RECs for the applicable percentage of its Standard Offer Service load in each calendar year, and, if necessary, remit ACPs. See Exhibit MJH-2 for a copy of the Company's Compliance Plan. The Company has purchased RECs to comply with its 2003 Standard Offer Service RPS obligation beginning in late 2002, at a cost of approximately $1.9 million, as is detailed in Mr. Hager's Exhibit MJH-3.

[1] The Company recently proposed amendments to its Default Service Adjustment Provision to provide for the

Also, the Company is subject to the cost of the GIS, which is assessed to Mass. Electric through monthly billings by ISO-NE. The GIS is necessary to assure compliance with the DOER's RPS regulations. Although the GIS has also been available since 2002 to be used in the development of environmental disclosure labels pursuant to Department regulations, Mass. Electric had not utilized the GIS in the preparation of its disclosure labels. Mr. Hager discusses these obligations and implementation issues in more detail in his testimony. Mass. Electric received its first GIS invoice from ISO-NE in October 2002 for GIS costs assessed from December 2001 through August 2002, and Mass. Electric has been assessed GIS charges monthly since this time. As Mr. Hager discusses, Mass. Electric has been billed approximately $861,000 by ISO-NE for GIS costs related to both Standard Offer Service and Default Service for the period December 2001 to September 2003. However, ISO-NE billed Mass. Electric approximately $534,000 during the 12-month period ending September 2002. In its annual *January 2003 Retail Rate Filing* in Docket No. D.T.E. 02-79, the Company indicated that it would not seek recovery of GIS costs incurred prior to October 2002, because, at that time, the Company's Standard Offer Service Cost Adjustment Provision and Default Service Adjustment Provision did not allow for the inclusion of this cost in the respective reconciliations. In addition, at that time the aggregate RPS and GIS costs did not exceed the $1 million threshold required under the Rate Settlement to be considered an exogenous factor.

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reconciliation of actual REC costs and ACPs with revenues collected from Default Service customers.

Nevertheless, the Company is including as part of its RPS compliance costs in this proceeding approximately $327,000 of GIS costs for the 12-month period ending September 2003. Together with the cost of purchasing RPS RECs, RPS compliance costs of approximately $2.2 million exceed the $1 million threshold for recovery of costs associated with new regulations as provided for in §I.C.1.b of the Rate Settlement. The monthly amounts are shown in Mr. Hager's Exhibit MJH-3.

As discussed by Mr. Hager in his testimony, the rules promulgated to implement the RPS requirements were established in April 2002. The determination that the rules governing RPS compliance are applicable to the Company and the assessment to the Company of GIS costs represent a regulatory change subsequent to the adoption of 225 CMR 14.00. Additionally, the threshold level of $1 million has been exceeded. Therefore these costs are eligible for recovery as an exogenous factor under the Rate Settlement as an adjustment to the Company's distribution rates.[2]

ISO-NE Charges Related to SMD

In addition to the costs listed above, there are costs which ISO-NE began billing to Mass. Electric in March 2003 as described by Mr. Hager, associated with load relating to two of its Standard Offer Service wholesale supply contracts. There is also a third supplier, as

[2] To the extent the Department authorizes an alternative mechanism for recovering Default Service-related GIS costs for which the Company is seeking recovery in this filing (e.g., as a direct adder to the retail Default Service rates or though the Default Service reconciliation), the Company would file to modify the exogenous factor proposed in this filing to remove Default Service GIS recovery.

explained by Mr. Hager, for which costs may be incurred related to this exogenous factor. However, Mass. Electric has not yet incurred such charges from this third supplier, and thus the exogenous factor recovery proposed in this filing does not reflect costs from this third supplier. Mass. Electric has paid ISO-NE for the charges that have been billed through September 2003, which total approximately $2.6 million, as shown in Mr. Hager's Exhibit MJH-7, as a result of the change in market rules stemming from the implementation of SMD. However, as discussed by Mr. Hager, Mass. Electric has sought to mitigate the impact of these costs on behalf of its customers by deducting approximately $1.5 million of the costs billed to it from ISO-NE as an offset against the amounts that it was billed by one of the two the Standard Offer Service suppliers. Therefore, the amount which Mass. Electric seeks to recover as part this filing is the net amount of approximately $1.1 million, as shown in Exhibit TMB-2, Line (3). Since these ISO-NE charges are being assessed to Mass. Electric pursuant to a regulatory rule change governing the operation of the wholesale market under SMD, they also qualify for exogenous factor recovery in accordance with §I.C.1.b of the Rate Settlement. Therefore, the Company is requesting such recovery through an adjustment to its distribution rates.

As discussed by Mr. Hager, Mass. Electric contends that these ISO-NE charges are not the responsibility of the Company, and as such is disputing them with the suppliers. To the extent that Mass. Electric ultimately incurs a cost associated with the $1.5 million it has offset, incurs costs relating to the third supplier that have not yet been billed to Mass.

Electric, or otherwise resolves the assessment of these charges with the suppliers, Mass. Electric will reconcile the charges it is seeking recovery of in this filing against the final actual costs associated with this exogenous factor, and will refund to or recover from customers the difference.

V. <u>Exogenous Factor Resulting from a Reclassification of Costs</u>

Q. Please describe in more detail the cost the Company has been incurring as a result of the reclassification of costs from transmission to generation.

A. Prior to the implementation of SMD, congestion costs were allocated throughout NEPOOL on the basis of Network Load, and were assessed as transmission costs. Following the implementation of SMD on March 1, 2003, the Company began incurring congestion costs associated with one Standard Offer Service contract, as described by Mr. Hager. However, since the mechanism that established this transfer of costs to generation occurred subsequent to the Company's execution of its Standard Offer Service contract and the approval of its Standard Service Cost Adjustment Provision, the Company, in essence, had no mechanism for recovery of this cost through its Standard Offer Service rates. This filing requests recovery of congestion cost pursuant to that contract as an exogenous factor. For the 7-month period ending September 2003, the Company has incurred approximately $1.8 million related to this reclassification of costs associated with the implementation of SMD, as shown in Exhibit TMB-2.

<u>Congestion Costs</u>

The Company has amended one of its Standard Offer Service contracts to address the treatment of changing congestion cost responsibilities under this contract as the result of the implementation by ISO-NE of SMD in New England beginning March 1, 2003. The purpose of this amendment is discussed in detail in Mr. Hager's testimony and was also the subject of a Company filing on February 27, 2003, which was addressed by the Department in Docket No. D.T.E. 03-67[3].

The Department, in its letter order in Docket No. D.T.E. 03-67, recognized that the market rules governing congestion costs changed significantly with the implementation of SMD on March 1, 2003. Prior to the implementation of SMD, congestion costs were allocated based on network load and these costs were assessed to transmission customers throughout New England. Consequently, until March 1, 2003, congestion costs were reflected in the Company's transmission charges to its customers. Subsequent to the implementation of SMD, congestion costs are reflected in the locational marginal price, or LMP, and are now a component of power supply costs, not transmission costs. Therefore, the reclassified congestion-related costs reflected in the amended contract are recoverable as an exogenous factor under §I.C.1.d of the Company's Rate Settlement, which provides for recovery of

[3] The Company submitted a request to the Department on February 27, 2003 in Docket No. D.T.E. 97-94 regarding the congestion obligation under the Standard Offer Service contract in question, seeking approval and rate treatment of the amendment which intended to minimize the cost of congestion to Mass. Electric Standard Offer Service customers. The Department docketed this matter as Docket No. D.T.E. 03-67. As part of that filing, the Company requested that the Department approve recovery of the costs related to the contract amendment as part of its Standard Offer Service reconciliation process. On August 20, 2003, the Department ruled that since the original wholesale Standard Offer Service supply contract was under the jurisdiction of the FERC, the Company must seek and obtain approval of the amendment to the original contract from FERC before the Department can consider the ratemaking treatment of the

costs associated with a regulatory rule change that results in a reclassification of costs from one function (in this case transmission) to another (distribution) in the form of higher Standard Offer Service supply costs[4]. This category of exogenous events has no monetary threshold, and therefore the cost reallocation qualifies for exogenous treatment. As the Department is aware, the Company did not include congestion costs in its transmission revenue requirement for 2003 beyond February 2003, anticipating a March 1, 2003 implementation of SMD, and thus the transmission rates paid by Mass. Electric customers in 2003 were correspondingly reduced by the amount of congestion reclassification. See Docket No. D.T.E. 02-79, Testimony of A. Rodrigues, p. 8. As a result, the benefit of the transfer of congestion costs away from transmission has been appropriately reflected in rates. The recovery of the exogenous factor associated with the reclassification assures that the costs that were shifted continue to be recovered, and that the reclassification is revenue neutral to the Company. Mr. Hager's Exhibit MJH-9 summarizes the incremental congestion costs paid to date under this amendment.

VI. <u>Cost Recovery</u>

Q. Has the Company reflected in rates the impact resulting from these tax changes, regulatory rule changes and the reclassification of costs through any mechanism?

A. No. In the case of the bonus tax depreciation allowance, this year is the first year that the $1

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amendment.

[4] In addition to being a reclassification of costs under the Rate Settlement, these congestion-related costs also qualify as an exogenous event due to a regulatory change under §I.C.1.b of the Rate Settlement. These are new costs which stem directly from the implementation of the FERC-approved SMD, and they exceed the $1 million annual cost threshold.

million threshold has been met in order to reflect the impact in rates to all retail delivery service customers. The Company has stated above that although the Rate Settlement clearly states that only a change in costs is to be considered for exogenous treatment, the intent of the language was to also include the impact of return on rate base resulting from a tax or accounting change. Due to the tax change yielding a higher deferred tax balance and therefore a lower rate base, the return on that rate base, and consequently the overall cost of service (or revenue requirement) is lower than it otherwise would have been absent the tax change. Therefore, the Company believes that it is appropriate to pass this benefit on to its customers through an exogenous factor.

In the case of the RPS regulations, the policies and costs that applied to the RPS obligation relating to the Company's Standard Offer Service and Default Service were developed after the Rate Settlement, as well as after wholesale Standard Offer Service contracts were executed. Other than the cost of RECs and ACPs relating to Default Service, RPS compliance costs were neither recovered in the rates of the Company's last resort services (Standard Offer Service and Default Service), allocated to wholesale suppliers of those services, nor reflected in the applicable reconciliation provisions for those services. Additionally, as explained by Mr. Hager, the reclassification of congestion costs from transmission to commodity was implemented as the result of ISO-NE's SMD filing, again after the wholesale Standard Offer Service contracts were executed. The reduction in transmission costs has already been reflected in the Company's transmission rates, but the reclassification of costs has not been. Today's filing includes only those costs that are being incurred by the Company and are not being borne by the wholesale Standard Offer Service or Default Service suppliers. The Company provides Standard Offer Service and Default Service at cost, without incurring a profit or loss. It is appropriate to reflect recovery of these externally-generated or third-party costs that are new or incurred due to a change in a market rule, such as those described above, as well as in Mr. Hager's testimony, in the rates to the Company's retail customers.

Q. Specifically relating to the Standard Offer Service costs discussed above, does the Company's Restructuring Settlement provide for an adjustment in the Standard Offer Service rate to recover these costs?

A. According to §I.B.5 of the Restructuring Settlement, the Standard Offer Service rates charged to customers during the term of Standard Offer Service are pre-determined, subject to a fuel index adjustment. Also provided for in §I.B.5 of the Restructuring Settlement, the Company is allowed to reconcile the revenues billed to Standard Offer Service customers against payments to suppliers of Standard Offer Service. To the extent the Company's Standard Offer reconciliation account reflects a surplus in a year, the Company is to credit all its retail delivery service customers through a uniform per kWh credit on their delivery rates the following year. However, to the extent the reconciliation account reflects a deficiency in a year, the Company is authorized to impose a surcharge on the rates for Standard Offer Service in the following year (subject to certain inflation cap limits), thus effectively increasing the Standard Offer Service rate.

At the time of the Restructuring Settlement, the parties to the settlement anticipated that the cost of providing Standard Offer Service would be limited to payments to suppliers with which the Company had contracts that reflected the stipulated contract price plus any fuel index payments. However, the rule changes that have been introduced in the past few years have directly increased the costs and obligations associated with providing Standard Offer Service. The development of the RPS regulations and the implementation of SMD have resulted in the Company making payments to entities historically not considered Standard Offer Service suppliers, such as to suppliers of RECs, to ISO-NE for certain generation-related services accompanying the procurement of Standard Offer Service supply, and to a Standard Offer Service supplier for increased costs under one Standard Offer Service contract (all of which are described more fully in Mr. Hager's testimony). In effect, the evolution of the wholesale energy market and the creation of new rules associated with the Standard Offer Service obligation have expanded what is required to be included in Standard Offer Service. These new costs clearly qualify as exogenous factors and the Company is proposing to recover these costs through the Factor included in this filing. Although a cost-causation approach would result in these costs being reflected in the Standard Offer Service rate (rather than assessed as a uniform charge to all customers), the Company's current Standard Offer Service provision does not provide for such treatment.

VII. Bill Impact

Q. Has the Company analyzed the bill impact of its proposal?

A. Yes it has. Exhibit TMB-3 presents the typical bills of Mass. Electric's rate classes. As can be seen, the impact on a 500 kWh residential customer is a bill increase of $0.07, or 0.1%, based on today's monthly bill of $58.23. It should be noted that these typical bills present the impact of this instant proposal based on today's rates and does not reflect any other rate changes that may occur in January 2004, as discussed below.

VIII. Proposed Tariffs

Q. Has the Company included its proposed tariff cover sheets for the implementation of the Factor, as discussed earlier in your testimony?

A. No it has not. Since several of the Company's rates and charges change on January 1 of each year, and the filings which propose these changes have not been made as of the date of this filing, the Company has not included proposed tariff cover sheets in order to avoid the confusion of having several versions of the tariff cover sheets for the same implementation date. Upon approval of all the Company's proposals for rates to become effective for January 2004, the Company will file with the Department a complete set of tariff cover sheets for both Mass. Electric and Nantucket Electric.

IX. Conclusion

Q. Does this conclude your testimony?

A. Yes it does.

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
M.D.T.E. No.
Witness: Burns

Exhibits

Exhibit TMB-1	Proposed Exogenous Factor Calculation
Exhibit TMB-2	Summary of Items to be Included in Exogenous Factor
Exhibit TMB-3	Typical Bills

Exhibit TMB-1

Proposed Exogenous Factor Calculation

Massachusetts Electric Company
Nantucket Electric Company

Calculation of Exogenous Factor

Effective January 1, 2004 - December 31, 2004

(1)	Total of Exogenous Factors	$3,119,843
(2)	Forecast 2004 kWh Sales (Mass. Electric and Nantucket)	21,962,044,216
(3)	Exogenous Factor per kWh	$0.00014

(1) Exhibit TMB-2, Line (5)
(2) Forecasted kWh sales
(3) Line (1) ÷ Line (2), truncated after 5 decimal places

Exhibit TMB-2

Summary of Items to be Included in Exogenous Factor

Massachusetts Electric Company
Nantucket Electric Company

Summary of Items
To Be Included in Exogenous Factor Recovery

		Incurred to Date
(1)	Bonus Depreciation Benefit	($2,064,714)
(2)	RPS Compliance Costs	$2,207,110
(3)	SMD Costs	$1,144,455
(4)	Congestion Costs	$1,832,992
(5)	Total	$3,119,843

(1) Exhibit MDL-1
(2) Exhibit MJH-1
(3) Exhibit MJH-1
(4) Exhibit MJH-1
(4) Sum of Lines (1) through (4)

Exhibit TMB-3

Mass. Electric Typical Bills

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on R-1 Rate Customers

	(1)			(2)			(1) vs (2)	
	Present Rates			Proposed Exogenous Factor			Overall Increase (Decrease)	
Monthly KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
125	$18.92	$7.66	$11.26	$18.94	$7.66	$11.28	$0.02	0.1%
250	$32.04	$15.31	$16.73	$32.08	$15.31	$16.77	$0.04	0.1%
500	$58.23	$30.62	$27.61	$58.30	$30.62	$27.68	$0.07	0.1%
750	$84.46	$45.93	$38.53	$84.57	$45.93	$38.64	$0.11	0.1%
1,000	$110.65	$61.24	$49.41	$110.79	$61.24	$49.55	$0.14	0.1%
1,250	$136.88	$76.55	$60.33	$137.06	$76.55	$60.51	$0.18	0.1%
1,500	$163.07	$91.86	$71.21	$163.28	$91.86	$71.42	$0.21	0.1%
2,000	$215.49	$122.48	$93.01	$215.77	$122.48	$93.29	$0.28	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$5.81	$5.81
Distribution Charge	KWh x	$0.02398	$0.02398
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.01002	$0.01002
Transmission Charge	KWh x	$0.00660	$0.00660
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on R-1 Rate Customers (with Interruptible Credit #1)

	(1)			(2)			(1) vs (2)	
	Present Rates			Proposed Exogenous Factor			Overall Increase (Decrease)	
Monthly KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
250	$26.52	$15.31	$11.21	$26.58	$15.31	$11.27	$0.06	0.2%
500	$52.73	$30.62	$22.11	$52.80	$30.62	$22.18	$0.07	0.1%
750	$78.94	$45.93	$33.01	$79.07	$45.93	$33.14	$0.13	0.2%
1,000	$105.15	$61.24	$43.91	$105.29	$61.24	$44.05	$0.14	0.1%
1,250	$131.36	$76.55	$54.81	$131.56	$76.55	$55.01	$0.20	0.2%
1,500	$157.57	$91.86	$65.71	$157.78	$91.86	$65.92	$0.21	0.1%
2,000	$209.99	$122.48	$87.51	$210.27	$122.48	$87.79	$0.28	0.1%
2,500	$262.41	$153.10	$109.31	$262.76	$153.10	$109.66	$0.35	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$5.81	$5.81
Distribution Charge	KWh x	$0.02398	$0.02398
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.01002	$0.01002
Transmission Charge	KWh x	$0.00660	$0.00660
Interruptible Credit #1		($5.50)	($5.50)
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on R-1 Rate Customers (with Interruptible Credit #2)

	/------------------ (1)	------------------/		/---------------- (2)	------------------/		(1) vs (2)	
		Present Rates			Proposed Exogenous Factor		Overall Increase (Decrease)	
Monthly KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
250	$24.52	$15.31	$9.21	$24.58	$15.31	$9.27	$0.06	0.2%
500	$50.73	$30.62	$20.11	$50.80	$30.62	$20.18	$0.07	0.1%
750	$76.94	$45.93	$31.01	$77.07	$45.93	$31.14	$0.13	0.2%
1,000	$103.15	$61.24	$41.91	$103.29	$61.24	$42.05	$0.14	0.1%
1,250	$129.36	$76.55	$52.81	$129.56	$76.55	$53.01	$0.20	0.2%
1,500	$155.57	$91.86	$63.71	$155.78	$91.86	$63.92	$0.21	0.1%
2,000	$207.99	$122.48	$85.51	$208.27	$122.48	$85.79	$0.28	0.1%
2,500	$260.41	$153.10	$107.31	$260.76	$153.10	$107.66	$0.35	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$5.81	$5.81
Distribution Charge	KWh x	$0.02398	$0.02398
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.01002	$0.01002
Transmission Charge	KWh x	$0.00660	$0.00660
Interruptible Credit #2		($7.50)	($7.50)
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
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Impact on R-2 Rate Customers

	(1)			(2)			(1) vs (2)	
	Present Rates			Proposed Exogenous Factor			Overall Increase (Decrease)	
Monthly KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
50	$7.82	$2.85	$4.97	$7.83	$2.85	$4.98	$0.01	0.1%
100	$11.84	$5.70	$6.14	$11.85	$5.70	$6.15	$0.01	0.1%
150	$15.89	$8.55	$7.34	$15.91	$8.55	$7.36	$0.02	0.1%
250	$23.97	$14.26	$9.71	$24.01	$14.26	$9.75	$0.04	0.2%
300	$27.99	$17.11	$10.88	$28.03	$17.11	$10.92	$0.04	0.1%
500	$44.14	$28.51	$15.63	$44.21	$28.51	$15.70	$0.07	0.2%
600	$52.20	$34.21	$17.99	$52.28	$34.21	$18.07	$0.08	0.2%
750	$64.32	$42.77	$21.55	$64.43	$42.77	$21.66	$0.11	0.2%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$3.77	$3.77
Distribution Charge	KWh x	$0.00359	$0.00359
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.01051	$0.01051
Transmission Charge	KWh x	$0.00660	$0.00660
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.05702	$0.05702

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
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Impact on R-2 Rate Customers
With Interruptible Credit #1

	(1)			(2)			(1) vs (2)	
		Present Rates			Proposed Exogenous Factor		Overall Increase (Decrease)	
Monthly KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
300	$22.49	$17.11	$5.38	$22.53	$17.11	$5.42	$0.04	0.2%
500	$38.63	$28.51	$10.12	$38.71	$28.51	$10.20	$0.08	0.2%
600	$46.70	$34.21	$12.49	$46.78	$34.21	$12.57	$0.08	0.2%
750	$58.82	$42.77	$16.05	$58.93	$42.77	$16.16	$0.11	0.2%
900	$70.92	$51.32	$19.60	$71.05	$51.32	$19.73	$0.13	0.2%
1,000	$78.99	$57.02	$21.97	$79.13	$57.02	$22.11	$0.14	0.2%
1,500	$119.35	$85.53	$33.82	$119.57	$85.53	$34.04	$0.22	0.2%
1,750	$139.54	$99.79	$39.75	$139.79	$99.79	$40.00	$0.25	0.2%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$3.77	$3.77
Distribution Charge	KWh x	$0.00359	$0.00359
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.01051	$0.01051
Transmission Charge	KWh x	$0.00660	$0.00660
Interruptible Credit #1		($5.50)	($5.50)
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.05702	$0.05702

Massachusetts Electric Company
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Impact on R-2 Rate Customers
With Interruptible Credit #2

	/------------------ (1)	------------------/		/---------------- (2)	------------------/		(1) vs (2)	
		Present Rates			Proposed Exogenous Factor		Overall Increase (Decrease)	
Monthly KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
300	$20.49	$17.11	$3.38	$20.53	$17.11	$3.42	$0.04	0.2%
500	$36.63	$28.51	$8.12	$36.71	$28.51	$8.20	$0.08	0.2%
600	$44.70	$34.21	$10.49	$44.78	$34.21	$10.57	$0.08	0.2%
750	$56.82	$42.77	$14.05	$56.93	$42.77	$14.16	$0.11	0.2%
900	$68.92	$51.32	$17.60	$69.05	$51.32	$17.73	$0.13	0.2%
1,000	$76.99	$57.02	$19.97	$77.13	$57.02	$20.11	$0.14	0.2%
1,500	$117.35	$85.53	$31.82	$117.57	$85.53	$32.04	$0.22	0.2%
1,750	$137.54	$99.79	$37.75	$137.79	$99.79	$38.00	$0.25	0.2%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$3.77	$3.77
Distribution Charge	KWh x	$0.00359	$0.00359
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.01051	$0.01051
Transmission Charge	KWh x	$0.00660	$0.00660
Interruptible Credit #2		($7.50)	($7.50)
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.05702	$0.05702

Massachusetts Electric Company
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Impact on R-4 Rate Customers

KWh Split: **- On-Peak** **25%**
- Off-Peak **75%**

Monthly KWh	(1) Present Rates Total	(1) Present Rates Standard Service	(1) Present Rates Retail Delivery	(2) Proposed Exogenous Factor Total	(2) Proposed Exogenous Factor Standard Service	(2) Proposed Exogenous Factor Retail Delivery	(1) vs (2) Overall Increase (Decrease) Amount	(1) vs (2) Overall Increase (Decrease) %
1,000	$109.56	$61.24	$48.32	$109.70	$61.24	$48.46	$0.14	0.1%
1,500	$154.73	$91.86	$62.87	$154.94	$91.86	$63.08	$0.21	0.1%
2,000	$199.94	$122.48	$77.46	$200.22	$122.48	$77.74	$0.28	0.1%
3,000	$290.28	$183.72	$106.56	$290.70	$183.72	$106.98	$0.42	0.1%
4,000	$380.64	$244.96	$135.68	$381.20	$244.96	$136.24	$0.56	0.1%
5,000	$471.00	$306.20	$164.80	$471.70	$306.20	$165.50	$0.70	0.1%
8,000	$742.08	$489.92	$252.16	$743.20	$489.92	$253.28	$1.12	0.2%
10,000	$922.82	$612.40	$310.42	$924.22	$612.40	$311.82	$1.40	0.2%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$19.20	$19.20
Distribution Charge: On Peak	KWh x	$0.06057	$0.06057
Distribution Charge: Off Peak	KWh x	$0.00281	$0.00281
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge: On Peak	KWh x	$0.02363	$0.02363
Transition Charge: Off Peak	KWh x	($0.00193)	($0.00193)
Transmission Charge: On Peak	KWh x	$0.00441	$0.00441
Transmission Charge: Off Peak	KWh x	$0.00441	$0.00441
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
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Impact on R-4 Rate Customers

KWh Split: **- On-Peak** **30%**
- Off-Peak **70%**

	(1)			(2)			(1) vs (2)	
	Present Rates			Proposed Exogenous Factor			Overall Increase (Decrease)	
Monthly KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
1,000	$113.73	$61.24	$52.49	$113.87	$61.24	$52.63	$0.14	0.1%
1,500	$160.99	$91.86	$69.13	$161.19	$91.86	$69.33	$0.20	0.1%
2,000	$208.25	$122.48	$85.77	$208.53	$122.48	$86.05	$0.28	0.1%
3,000	$302.78	$183.72	$119.06	$303.20	$183.72	$119.48	$0.42	0.1%
4,000	$397.30	$244.96	$152.34	$397.87	$244.96	$152.91	$0.57	0.1%
5,000	$491.83	$306.20	$185.63	$492.55	$306.20	$186.35	$0.72	0.1%
8,000	$775.41	$489.92	$285.49	$776.53	$489.92	$286.61	$1.12	0.1%
10,000	$964.46	$612.40	$352.06	$965.86	$612.40	$353.46	$1.40	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$19.20	$19.20
Distribution Charge: On Peak	KWh x	$0.06057	$0.06057
Distribution Charge: Off Peak	KWh x	$0.00281	$0.00281
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge: On Peak	KWh x	$0.02363	$0.02363
Transition Charge: Off Peak	KWh x	($0.00193)	($0.00193)
Transmission Charge: On Peak	KWh x	$0.00441	$0.00441
Transmission Charge: Off Peak	KWh x	$0.00441	$0.00441
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
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Impact on R-4 Rate Customers

KWh Split: **- On-Peak** **40%**
- Off-Peak **60%**

	(1)			(2)			(1) vs (2)	
	Present Rates			Proposed Exogenous Factor			Overall Increase (Decrease)	
Monthly KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
1,000	$122.06	$61.24	$60.82	$122.20	$61.24	$60.96	$0.14	0.1%
1,500	$173.49	$91.86	$81.63	$173.70	$91.86	$81.84	$0.21	0.1%
2,000	$224.92	$122.48	$102.44	$225.19	$122.48	$102.71	$0.27	0.1%
3,000	$327.77	$183.72	$144.05	$328.20	$183.72	$144.48	$0.43	0.1%
4,000	$430.63	$244.96	$185.67	$431.19	$244.96	$186.23	$0.56	0.1%
5,000	$533.49	$306.20	$227.29	$534.19	$306.20	$227.99	$0.70	0.1%
8,000	$842.06	$489.92	$352.14	$843.19	$489.92	$353.27	$1.13	0.1%
10,000	$1,047.78	$612.40	$435.38	$1,049.18	$612.40	$436.78	$1.40	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$19.20	$19.20
Distribution Charge: On Peak	KWh x	$0.06057	$0.06057
Distribution Charge: Off Peak	KWh x	$0.00281	$0.00281
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge: On Peak	KWh x	$0.02363	$0.02363
Transition Charge: Off Peak	KWh x	($0.00193)	($0.00193)
Transmission Charge: On Peak	KWh x	$0.00441	$0.00441
Transmission Charge: Off Peak	KWh x	$0.00441	$0.00441
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
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Calculation of Monthly Typical Bill

Impact on G-1 Rate Customers

	(1)			(2)			(1) vs (2)	
	Present Rates			Proposed Exogenous Factor			Overall Increase (Decrease)	
Monthly KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
50	$14.24	$3.06	$11.18	$14.25	$3.06	$11.19	$0.01	0.1%
100	$20.14	$6.12	$14.02	$20.15	$6.12	$14.03	$0.01	0.0%
250	$37.88	$15.31	$22.57	$37.92	$15.31	$22.61	$0.04	0.1%
500	$67.43	$30.62	$36.81	$67.50	$30.62	$36.88	$0.07	0.1%
1,000	$126.52	$61.24	$65.28	$126.66	$61.24	$65.42	$0.14	0.1%
2,500	$303.83	$153.10	$150.73	$304.18	$153.10	$151.08	$0.35	0.1%
5,000	$599.32	$306.20	$293.12	$600.02	$306.20	$293.82	$0.70	0.1%
7,500	$894.83	$459.30	$435.53	$895.88	$459.30	$436.58	$1.05	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$8.32	$8.32
Distribution Charge	KWh x	$0.03739	$0.03739
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00972	$0.00972
Transmission Charge	KWh x	$0.00685	$0.00685
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
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Impact on G-2 Rate Customers

Hours Use: 200

		(1)			(2)			(1) vs (2)	
Monthly Power		Present Rates			Proposed Exogenous Factor			Overall Increase (Decrease)	
KW	KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
15	3,000	$353.45	$183.72	$169.73	$353.87	$183.72	$170.15	$0.42	0.1%
20	4,000	$466.19	$244.96	$221.23	$466.75	$244.96	$221.79	$0.56	0.1%
40	8,000	$917.15	$489.92	$427.23	$918.27	$489.92	$428.35	$1.12	0.1%
75	15,000	$1,706.33	$918.60	$787.73	$1,708.43	$918.60	$789.83	$2.10	0.1%
150	30,000	$3,397.43	$1,837.20	$1,560.23	$3,401.63	$1,837.20	$1,564.43	$4.20	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$15.23	$15.23
Distribution Demand Charge	KW x	$5.92	$5.92
Transition Demand Charge	KW x	$0.98	$0.98
Distribution Charge	KWh x	$0.00034	$0.00034
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00734	$0.00734
Transmission Charge	KWh x	$0.00632	$0.00632
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
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Impact on G-2 Rate Customers

Hours Use: 250

Monthly Power		(1) Present Rates			(2) Proposed Exogenous Factor			(1) vs (2) Overall Increase (Decrease)	
KW	KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
15	3,750	$412.15	$229.65	$182.50	$412.68	$229.65	$183.03	$0.53	0.1%
20	5,000	$544.43	$306.20	$238.23	$545.13	$306.20	$238.93	$0.70	0.1%
40	10,000	$1,073.63	$612.40	$461.23	$1,075.03	$612.40	$462.63	$1.40	0.1%
75	18,750	$1,999.75	$1,148.25	$851.50	$2,002.38	$1,148.25	$854.13	$2.63	0.1%
150	37,500	$3,984.23	$2,296.50	$1,687.73	$3,989.48	$2,296.50	$1,692.98	$5.25	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$15.23	$15.23
Distribution Demand Charge	KW x	$5.92	$5.92
Transition Demand Charge	KW x	$0.98	$0.98
Distribution Charge	KWh x	$0.00034	$0.00034
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00734	$0.00734
Transmission Charge	KWh x	$0.00632	$0.00632
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
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Impact on G-2 Rate Customers

Hours Use: 300

Monthly Power KW	KWh	(1) Present Rates Total	(1) Present Rates Standard Service	(1) Present Rates Retail Delivery	(2) Proposed Exogenous Factor Total	(2) Proposed Exogenous Factor Standard Service	(2) Proposed Exogenous Factor Retail Delivery	(1) vs (2) Overall Increase (Decrease) Amount	(1) vs (2) Overall Increase (Decrease) %
15	4,500	$470.81	$275.58	$195.23	$471.44	$275.58	$195.86	$0.63	0.1%
20	6,000	$622.67	$367.44	$255.23	$623.51	$367.44	$256.07	$0.84	0.1%
40	12,000	$1,230.11	$734.88	$495.23	$1,231.79	$734.88	$496.91	$1.68	0.1%
75	22,500	$2,293.13	$1,377.90	$915.23	$2,296.28	$1,377.90	$918.38	$3.15	0.1%
150	45,000	$4,571.03	$2,755.80	$1,815.23	$4,577.33	$2,755.80	$1,821.53	$6.30	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$15.23	$15.23
Distribution Demand Charge	KW x	$5.92	$5.92
Transition Demand Charge	KW x	$0.98	$0.98
Distribution Charge	KWh x	$0.00034	$0.00034
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00734	$0.00734
Transmission Charge	KWh x	$0.00632	$0.00632
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

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Impact on G-2 Rate Customers

Hours Use: 350

Monthly Power KW	KWh	(1) Present Rates Total	(1) Present Rates Standard Service	(1) Present Rates Retail Delivery	(2) Proposed Exogenous Factor Total	(2) Proposed Exogenous Factor Standard Service	(2) Proposed Exogenous Factor Retail Delivery	(1) vs (2) Overall Increase (Decrease) Amount	(1) vs (2) Overall Increase (Decrease) %
15	5,250	$529.51	$321.51	$208.00	$530.25	$321.51	$208.74	$0.74	0.1%
20	7,000	$700.91	$428.68	$272.23	$701.89	$428.68	$273.21	$0.98	0.1%
40	14,000	$1,386.59	$857.36	$529.23	$1,388.55	$857.36	$531.19	$1.96	0.1%
75	26,250	$2,586.55	$1,607.55	$979.00	$2,590.23	$1,607.55	$982.68	$3.68	0.1%
150	52,500	$5,157.83	$3,215.10	$1,942.73	$5,165.18	$3,215.10	$1,950.08	$7.35	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$15.23	$15.23
Distribution Demand Charge	KW x	$5.92	$5.92
Transition Demand Charge	KW x	$0.98	$0.98
Distribution Charge	KWh x	$0.00034	$0.00034
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00734	$0.00734
Transmission Charge	KWh x	$0.00632	$0.00632
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on G-2 Rate Customers

Hours Use: 400

Monthly Power		(1) Present Rates			(2) Proposed Exogenous Factor			(1) vs (2) Overall Increase (Decrease)	
KW	KWh	Total	Standard Service	Retail Delivery	Total	Standard Service	Retail Delivery	Amount	%
15	6,000	$588.17	$367.44	$220.73	$589.01	$367.44	$221.57	$0.84	0.1%
20	8,000	$779.15	$489.92	$289.23	$780.27	$489.92	$290.35	$1.12	0.1%
40	16,000	$1,543.07	$979.84	$563.23	$1,545.31	$979.84	$565.47	$2.24	0.1%
75	30,000	$2,879.93	$1,837.20	$1,042.73	$2,884.13	$1,837.20	$1,046.93	$4.20	0.1%
150	60,000	$5,744.63	$3,674.40	$2,070.23	$5,753.03	$3,674.40	$2,078.63	$8.40	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$15.23	$15.23
Distribution Demand Charge	KW x	$5.92	$5.92
Transition Demand Charge	KW x	$0.98	$0.98
Distribution Charge	KWh x	$0.00034	$0.00034
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00734	$0.00734
Transmission Charge	KWh x	$0.00632	$0.00632
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on G-2 Rate Customers

Hours Use: 450

Monthly Power KW	KWh	(1) Present Rates Total	(1) Present Rates Standard Service	(1) Present Rates Retail Delivery	(2) Proposed Exogenous Factor Total	(2) Proposed Exogenous Factor Standard Service	(2) Proposed Exogenous Factor Retail Delivery	(1) vs (2) Overall Increase (Decrease) Amount	(1) vs (2) Overall Increase (Decrease) %
15	6,750	$646.87	$413.37	$233.50	$647.82	$413.37	$234.45	$0.95	0.1%
20	9,000	$857.39	$551.16	$306.23	$858.65	$551.16	$307.49	$1.26	0.1%
40	18,000	$1,699.55	$1,102.32	$597.23	$1,702.07	$1,102.32	$599.75	$2.52	0.1%
75	33,750	$3,173.35	$2,066.85	$1,106.50	$3,178.08	$2,066.85	$1,111.23	$4.73	0.1%
150	67,500	$6,331.43	$4,133.70	$2,197.73	$6,340.88	$4,133.70	$2,207.18	$9.45	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$15.23	$15.23
Distribution Demand Charge	KW x	$5.92	$5.92
Transition Demand Charge	KW x	$0.98	$0.98
Distribution Charge	KWh x	$0.00034	$0.00034
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00734	$0.00734
Transmission Charge	KWh x	$0.00632	$0.00632
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on G-3 Rate Customers

Hours Use: 250

KWh Split: **- On-Peak** **55%**
- Off-Peak **45%**

Monthly Power KW	KWh	(1) Present Rates Total	(1) Present Rates Standard Service	(1) Present Rates Retail Delivery	(2) Proposed Exogenous Factor Total	(2) Proposed Exogenous Factor Standard Service	(2) Proposed Exogenous Factor Retail Delivery	(1) vs (2) Overall Increase (Decrease) Amount	(1) vs (2) Overall Increase (Decrease) %
600	150,000	$15,332.70	$9,186.00	$6,146.70	$15,353.70	$9,186.00	$6,167.70	$21.00	0.1%
800	200,000	$20,421.17	$12,248.00	$8,173.17	$20,449.17	$12,248.00	$8,201.17	$28.00	0.1%
1,000	250,000	$25,509.65	$15,310.00	$10,199.65	$25,544.65	$15,310.00	$10,234.65	$35.00	0.1%
1,500	375,000	$38,230.83	$22,965.00	$15,265.83	$38,283.33	$22,965.00	$15,318.33	$52.50	0.1%
3,000	750,000	$76,394.40	$45,930.00	$30,464.40	$76,499.40	$45,930.00	$30,569.40	$105.00	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$67.27	$67.27
Distribution Demand Charge	KW x	$3.63	$3.63
Transition Demand Charge	KW x	$1.65	$1.65
Distribution Charge: On Peak	KWh x	$0.01017	$0.01017
Distribution Charge: Off Peak	KWh x	($0.00052)	($0.00052)
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00567	$0.00567
Transmission Charge	KWh x	$0.00538	$0.00538
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on G-3 Rate Customers

Hours Use: 300

KWh Split: **- On-Peak** **50%**
- Off-Peak **50%**

Monthly Power KW	KWh	(1) Present Rates Total	(1) Present Rates Standard Service	(1) Present Rates Retail Delivery	(2) Proposed Exogenous Factor Total	(2) Proposed Exogenous Factor Standard Service	(2) Proposed Exogenous Factor Retail Delivery	(1) vs (2) Overall Increase (Decrease) Amount	%
600	180,000	$17,655.97	$11,023.20	$6,632.77	$17,681.17	$11,023.20	$6,657.97	$25.20	0.1%
800	240,000	$23,518.87	$14,697.60	$8,821.27	$23,552.47	$14,697.60	$8,854.87	$33.60	0.1%
1,000	300,000	$29,381.77	$18,372.00	$11,009.77	$29,423.77	$18,372.00	$11,051.77	$42.00	0.1%
1,500	450,000	$44,039.02	$27,558.00	$16,481.02	$44,102.02	$27,558.00	$16,544.02	$63.00	0.1%
3,000	900,000	$88,010.77	$55,116.00	$32,894.77	$88,136.77	$55,116.00	$33,020.77	$126.00	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$67.27	$67.27
Distribution Demand Charge	KW x	$3.63	$3.63
Transition Demand Charge	KW x	$1.65	$1.65
Distribution Charge: On Peak	KWh x	$0.01017	$0.01017
Distribution Charge: Off Peak	KWh x	($0.00052)	($0.00052)
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00567	$0.00567
Transmission Charge	KWh x	$0.00538	$0.00538
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on G-3 Rate Customers

Hours Use: 350

KWh Split: **- On-Peak** **50%**
- Off-Peak **50%**

Monthly Power KW	KWh	(1) Present Rates Total	(1) Present Rates Standard Service	(1) Present Rates Retail Delivery	(2) Proposed Exogenous Factor Total	(2) Proposed Exogenous Factor Standard Service	(2) Proposed Exogenous Factor Retail Delivery	(1) vs (2) Overall Increase (Decrease) Amount	(1) vs (2) Overall Increase (Decrease) %
600	210,000	$20,059.42	$12,860.40	$7,199.02	$20,088.82	$12,860.40	$7,228.42	$29.40	0.1%
800	280,000	$26,723.47	$17,147.20	$9,576.27	$26,762.67	$17,147.20	$9,615.47	$39.20	0.1%
1,000	350,000	$33,387.52	$21,434.00	$11,953.52	$33,436.52	$21,434.00	$12,002.52	$49.00	0.1%
1,500	525,000	$50,047.65	$32,151.00	$17,896.65	$50,121.15	$32,151.00	$17,970.15	$73.50	0.1%
3,000	1,050,000	$100,028.02	$64,302.00	$35,726.02	$100,175.02	$64,302.00	$35,873.02	$147.00	0.1%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$67.27	$67.27
Distribution Demand Charge	KW x	$3.63	$3.63
Transition Demand Charge	KW x	$1.65	$1.65
Distribution Charge: On Peak	KWh x	$0.01017	$0.01017
Distribution Charge: Off Peak	KWh x	($0.00052)	($0.00052)
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00567	$0.00567
Transmission Charge	KWh x	$0.00538	$0.00538
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on G-3 Rate Customers

Hours Use: 400

KWh Split: **- On-Peak** **45%**
- Off-Peak **55%**

Monthly Power KW	KWh	(1) Present Rates Total	Standard Service	Retail Delivery	(2) Proposed Exogenous Factor Total	Standard Service	Retail Delivery	(1) vs (2) Overall Increase (Decrease) Amount	%
600	240,000	$22,334.59	$14,697.60	$7,636.99	$22,368.19	$14,697.60	$7,670.59	$33.60	0.2%
800	320,000	$29,757.03	$19,596.80	$10,160.23	$29,801.83	$19,596.80	$10,205.03	$44.80	0.2%
1,000	400,000	$37,179.47	$24,496.00	$12,683.47	$37,235.47	$24,496.00	$12,739.47	$56.00	0.2%
1,500	600,000	$55,735.57	$36,744.00	$18,991.57	$55,819.57	$36,744.00	$19,075.57	$84.00	0.2%
3,000	1,200,000	$111,403.87	$73,488.00	$37,915.87	$111,571.87	$73,488.00	$38,083.87	$168.00	0.2%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$67.27	$67.27
Distribution Demand Charge	KW x	$3.63	$3.63
Transition Demand Charge	KW x	$1.65	$1.65
Distribution Charge: On Peak	KWh x	$0.01017	$0.01017
Distribution Charge: Off Peak	KWh x	($0.00052)	($0.00052)
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00567	$0.00567
Transmission Charge	KWh x	$0.00538	$0.00538
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

Supplier Services

Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on G-3 Rate Customers

Hours Use: 450

KWh Split: **- On-Peak** **45%**
- Off-Peak **55%**

Monthly Power KW	KWh	(1) Present Rates Total	(1) Present Rates Standard Service	(1) Present Rates Retail Delivery	(2) Proposed Exogenous Factor Total	(2) Proposed Exogenous Factor Standard Service	(2) Proposed Exogenous Factor Retail Delivery	(1) vs (2) Overall Increase (Decrease) Amount	(1) vs (2) Overall Increase (Decrease) %
600	270,000	$24,722.01	$16,534.80	$8,187.21	$24,759.81	$16,534.80	$8,225.01	$37.80	0.2%
800	360,000	$32,940.25	$22,046.40	$10,893.85	$32,990.65	$22,046.40	$10,944.25	$50.40	0.2%
1,000	450,000	$41,158.50	$27,558.00	$13,600.50	$41,221.50	$27,558.00	$13,663.50	$63.00	0.2%
1,500	675,000	$61,704.11	$41,337.00	$20,367.11	$61,798.61	$41,337.00	$20,461.61	$94.50	0.2%
3,000	1,350,000	$123,340.95	$82,674.00	$40,666.95	$123,529.95	$82,674.00	$40,855.95	$189.00	0.2%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$67.27	$67.27
Distribution Demand Charge	KW x	$3.63	$3.63
Transition Demand Charge	KW x	$1.65	$1.65
Distribution Charge: On Peak	KWh x	$0.01017	$0.01017
Distribution Charge: Off Peak	KWh x	($0.00052)	($0.00052)
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00567	$0.00567
Transmission Charge	KWh x	$0.00538	$0.00538
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050
Supplier Services			
Standard Service Charge	KWh x	$0.06124	$0.06124

Massachusetts Electric Company
Proposed January 1, 2004 Exogenous Factor
Calculation of Monthly Typical Bill

Impact on G-3 Rate Customers

Hours Use: 500

KWh Split: **- On-Peak** **45%**
- Off-Peak **55%**

		(1)			(2)			(1) vs (2)	
Monthly Power KW	KWh	Present Rates Total	Standard Service	Retail Delivery	Proposed Exogenous Factor Total	Standard Service	Retail Delivery	Overall Increase (Decrease) Amount	%
600	300,000	$27,109.42	$18,372.00	$8,737.42	$27,151.42	$18,372.00	$8,779.42	$42.00	0.2%
800	400,000	$36,123.47	$24,496.00	$11,627.47	$36,179.47	$24,496.00	$11,683.47	$56.00	0.2%
1,000	500,000	$45,137.52	$30,620.00	$14,517.52	$45,207.52	$30,620.00	$14,587.52	$70.00	0.2%
1,500	750,000	$67,672.65	$45,930.00	$21,742.65	$67,777.65	$45,930.00	$21,847.65	$105.00	0.2%
3,000	1,500,000	$135,278.02	$91,860.00	$43,418.02	$135,488.02	$91,860.00	$43,628.02	$210.00	0.2%

		Present Rates	Proposed Exogenous Factor
Customer Charge		$67.27	$67.27
Distribution Demand Charge	KW x	$3.63	$3.63
Transition Demand Charge	KW x	$1.65	$1.65
Distribution Charge: On Peak	KWh x	$0.01017	$0.01017
Distribution Charge: Off Peak	KWh x	($0.00052)	($0.00052)
Exogenous Factor	KWh x	n/a	$0.00014
Transition Charge	KWh x	$0.00567	$0.00567
Transmission Charge	KWh x	$0.00538	$0.00538
DSM Charge	KWh x	$0.00250	$0.00250
Renewables Charge	KWh x	$0.00050	$0.00050

<u>Supplier Services</u>

Standard Service Charge	KWh x	$0.06124	$0.06124

DIRECT TESTIMONY

OF

MICHAEL D. LAFLAMME

Table of Contents

I. Introduction and Qualifications

Q. Please state your full name and business address.

A. My name is Michael D. Laflamme. My business address is 55 Bearfoot Road, Northboro, Massachusetts 01532.

Q. By whom are you employed and in what position?

A. I am Manager of Regulatory Support for National Grid USA Service Company Inc. National Grid USA Service Company provides engineering, financial, administrative and other technical support to subsidiary companies of National Grid USA, including Massachusetts Electric Company and Nantucket Electric Company (collectively "MECO", or "Company").

Q. Please provide a brief summary of your educational background and training.

A. In 1981 I earned a Bachelor of Science degree in Business Administration, emphasis in Accounting, from Bryant College in Smithfield, Rhode Island.

Q. What is your professional background?

A. From 1981 through April 2000 I was employed by various subsidiary companies of Eastern Utilities Associates ("EUA"), including the former Eastern Edison Company, which merged with MECo in 2000, the former Blackstone Valley Electric Company ("Blackstone") and the former EUA Service Corporation ("EUASC") which provided various accounting, financial, engineering, planning, data processing and other services to all EUA System companies.

I joined Blackstone in 1981 as a junior accountant and attained a staff accountant position prior to transferring to the revenue requirements section of EUASC's Rate Department in 1985. I held progressively more responsible positions in revenue requirements prior to transferring to the Treasury Services department of EUASC in 1988. I was promoted to the position of Manager of Treasury Services in 1991. The EUA System was acquired by National Grid USA in early 2000, at which time I joined the National Grid USA.

Q. What is your relationship to MECO?

A. My current duties include supporting cost of service and revenue requirements analyses for the National Grid USA Distribution companies in New England, including MECO.

Q. Have you previously testified before a regulatory commission?

A. Yes, I have testified in proceedings before the Massachusetts Department of Telecommunications and Energy ("Commission"), the Rhode Island Public Utilities Commission and the New Hampshire Public Utilities Commission. I have also provided primary support for revenue requirements witnesses in proceedings before the Federal Energy Regulatory Commission.

II. **Purpose Of Testimony**

Q. What is the purpose of this testimony?

A. My testimony explains and quantifies a 2003 exogenous event as defined in the Rate Plan Settlement dated November 29, 1999 in Docket D.T.E. 99-47 (the "Settlement"). Pursuant to the Settlement, during the Company's Rate Cap Period which extends through February 2005, the Company's distribution rates are subject to adjustment for certain exogenous factors as described in §I.C of the Settlement. One such factor, as described in §I.C.1.a, provides for the following:

> Tax and Accounting Changes: Mass Electric shall adjust its distribution rates for effects of any externally imposed accounting changes and for the effects associated with any changes in the federal, state or local rates, laws, regulations, or precedents governing income, revenue, sales, franchise or property taxes if the accounting and tax changes individually affect Mass. Electric's costs by more than $1 million per year.

The Job Creation and Worker Assistance Act of 2002, signed into law in March of 2002, amended the Internal Revenue Code Section 168 by adding a subsection (k) - Special Allowance for Certain Property Acquired After September 10, 2001 and Before September 11, 2004 ("IRC 168(k)"). IRC 168(k) provides for additional first year tax depreciation deductions for certain qualified property ("Bonus Depreciation"). The Company believes that the impact of this Bonus Depreciation allowance constitutes an exogenous factor as described in §I.C.1.a.

III. **IRC 168(k)**

Q. Would you summarize IRC 168 (k)?

A. Certainly. IRC 168(k), as enacted, provides for an additional 30% first year tax depreciation deduction for qualified property in addition to the first year tax deduction pursuant to the Modified Accelerated Cost Recovery System ("MACRS") on the remaining 70% of that property. Since 1997, for tax purposes, depreciable property has generally been classified into individual MACRS class lives and depreciated at stipulated annual percentages associated with each class life. For example, property classified as 20 Year Utility Plant has a first year MACRS depreciation rate of 3.75%. Assuming a $100 qualifying property addition, normal MACRS first year tax depreciation, absent IRC 168(k), would be $3.75 ($100 * 3.75%). Pursuant to IRC 168(k), the first year tax depreciation deduction for the same $100 qualifying property would be $32.63 [($100 * 30%) + ($100 – ($100 * 30%)) * 3.75%], or an additional first year tax deduction of 28.88% of qualifying property additions.

Q. Can you summarize what property additions qualify for this Bonus Depreciation?

A. In general, to qualify, property must satisfy four requirements as listed below:

1. Must be MACRS tangible personal property with a class life of 20 years or less;
2. the original use of the property must have begun with the taxpayer after September 10, 2001;
3. the property must have been:

(a) acquired after September 10, 2001 and before September 11, 2004, but only if no written binding contract for the acquisition was in effect before September 11, 2001; and

(b) acquired under a written binding contract which was entered into after September 10, 2001 and before September 11, 2004; and

4. if qualified, property must be placed in service by the taxpayer before January 1, 2005, except for self constructed property, as defined by the code, for which the in-service date is extended to January 1, 2006 if certain requirements are met.

Q. Have there been any modifications to the Bonus Depreciation rules since enacted?

A. Yes. In 2003, the first year bonus depreciation was increased from 30% to 50% for qualifying property placed in-service after May 5, 2003. The new first year tax depreciation deduction for a $100 qualifying property addition placed in-service after May 5, 2003 is $51.88 [($100 * 50%) + ($100 – ($100 * 50%)) * 3.75%], or an additional first year tax deduction of 48.13% of qualifying property additions. In addition, the statutory changes extended the in service and acquisition date deadlines to on or before December 31, 2004.

IV. Bonus Depreciation - 2003 Exogenous Factor

Q. What Company "costs" are affected by the IRC 168(k) bonus tax depreciation deduction?

A. Because the Company normalizes book/tax depreciation rate differences, this bonus tax depreciation does not directly affect "costs" (total income tax expense) that the Company records and recovers through distribution rates.

Q. What does 'normalizing book/tax depreciation rate differences' mean?

A. While the yearly depreciation rates differ for book and tax purposes, over the life of an asset, the sum of all the yearly depreciation rates equals 100% for both book and tax. In general, for book purposes the Company employs a straight line depreciation schedule over the individual property life. Tax depreciation schedules are generally accelerated providing for higher depreciation rates in earlier years. Consequently, the difference in the accumulated book versus accumulated tax depreciation on a given depreciable asset is temporary and will reverse to zero over the life of the asset being depreciated. As required by the Internal Revenue Service and D.T.E. policy, in addition to the Company's current, or cash, income tax liability, the Company provides for and recovers from, or credits to, its customers deferred taxes equal to the tax impact of the current year book/tax depreciation difference. In years that tax depreciation expense exceeds book depreciation expense (the annual tax depreciation rate is higher than the book depreciation rate) deferred taxes are accumulated and recovered from customers. In years that the opposite occurs, book depreciation exceeds tax depreciation, the deferred taxes are reversed and credited to customers. In general, each year the Company records and recovers total (current plus deferred) income tax expense equal to the statutory income tax rate. As a result, these accumulated deferred income taxes are included in the derivation of the Company's rate base.

Q. If IRC 168(k) Bonus Depreciation does not affect total income taxes recorded and recovered by the Company, why does it constitute an exogenous factor pursuant to the Settlement?

A. As previously mentioned, the Bonus Depreciation does impact the Company's rate base, upon which the Company earns a return that is recovered through distribution rates. The accelerated tax deduction for Bonus Depreciation will generate additional deferred tax in the year that qualifying property is added and consequently will have a decreasing impact on the Company's rate base. While "costs" are not directly affected, the Company will experience an economic benefit related to a lower current, or cash, income tax liability. Thus, the benefit the Company proposes to treat as an exogenous event is its reduced annual revenue requirement. This is determined by applying the Company's allowed pre-tax rate of return to the reduction in the Company's rate base resulting from the Bonus Depreciation. The Company believes that this kind of economic impact constitutes an exogenous event to the extent that the reduction in its current year revenue requirement exceeds the stipulated thresholds pursuant to terms of §I.C.1.a of the Settlement.

V. Calculation Of 2003 Exogenous Amount – Bonus Depreciation

Q. How was the exogenous factor related to Bonus Depreciation calculated?

A. The 2003 annual amount for the exogenous factor related to the Bonus Depreciation deduction is quantified by calculating the cumulative increase in the Company's deferred tax reserves resulting from the Bonus Depreciation and applying the Company's pre-tax weighted average cost of capital ("WACC"). The Company has recognized bonus depreciation for calendar years 2001, 2002 and 2003 on two classes of property, 20 year utility and 7 year utility property. Exhibit MDL-2 and Exhibit MDL-3 quantify the impact of the Bonus Depreciation for 20 year utility and 7 year utility qualifying depreciable property added during these years.

Q. Can you describe the calculations shown on these exhibits?

A. Certainly. Because the first year Bonus Depreciation deduction is the same for both classes of qualifying property, albeit the deduction increased from 30% to 50% effective May 5, 2003, the calculation of the annual return impact is identical for both classes of property, differing only by the stipulated MACRS depreciation rate schedule for each class of property and the respective bonus percentage. As a result of the 30% to 50% change in the amount of the first year bonus deduction, the attached exhibits' designations include a "30% Bonus" or "50% Bonus" extension in order to further identify individual property class additions in calendar year 2003.

The calculations illustrated on Exhibits MDL-2 and MDL-3 simply relate to different classes of property and substitute the MACRS depreciation rates for that respective class of property, as shown in Column 1 and substitute the 50% bonus, in Column 2, if appropriate. I will describe the mechanics of the calculation for MACRS 20 Utility Property qualifying for the 30% bonus depreciation, shown on Exhibit MDL-2, Page 1.

Referring to Exhibit MDL-2, Page 1, Column 1 lists the MACRS tax depreciation rate schedule for 20 year utility property and indicates a tax depreciation rate of 3.75% as shown for Year 1, Column 1 of that exhibit. The tax depreciation rate schedule pursuant to the bonus depreciation rules of IRC 168(k) are listed in Column 2 of that exhibit. As shown in Column 2, the Year 1 tax depreciation rate including the 30% bonus is 32.63% and is derived by adding the first year 30% bonus to the normal MACRS depreciation rate on the remaining 70%, or 2.63% (3.75% * 70%). For all subsequent years, the IRC 168(k) tax depreciation rate is derived by multiplying the normal MACRS rate for a particular year by the remaining 70%, as shown in Column 2. Column 3 represents the net difference in yearly tax depreciation rates between normal MACRS Rates and IRC 168(k) bonus depreciation rates, Column 2 minus Column 1. Column 5, lists, by year, the 20 year utility plant additions qualifying for the 30% bonus. Columns 6 through 8 represent the annual deferred tax differences of the vintage year additions and equal the yearly tax depreciation percentage differences listed in Column 3 times the vintage year addition listed in Column 5 times the Federal income tax rate of 35%, with the year 1 percentage difference commencing in the year of addition. The cumulative deferred tax difference, listed in Column 9, equals the previous year amount in Column 9 plus the current year amounts from Columns 6 through 8. Column 10 represents a simple two year average of prior and current year cumulative deferred tax amounts. The Company's

WACC is applied to the average cumulative deferred tax differences shown in Column 10 to arrive at the annual return impacts shown in Column 11. Column 11, therefore, represents the economic benefit the Company realizes related to 20 year utility property additions which qualified for the 30% IRC 168(k) bonus depreciation. Exhibit MDL-1 summarizes the economic benefits of all classes of property additions which qualified for both the 30% and 50% bonus tax depreciation deductions for calendar years 2001, 2002, and 2003.

Q. Were the Bonus Depreciation rules for tax depreciation deductions for federal income tax calculations extended to the calculation of Massachusetts corporate state income taxes?

A. No, they were not.

Q. Do the vintage year additions listed in Column 5 represent actual property additions for the years listed?

A. For financial and tax reporting purposes, the Company is on a fiscal year ending March 31 rather than a calendar year. Consequently, tax records are accumulated and reported for the twelve month periods ending March 31. Because tax depreciation is an annual deduction, it is appropriate to allocate fiscal year tax depreciation to calendar years based on the number of months in each calendar year. For the fiscal year ending March 2002, the actual property additions qualifying for bonus depreciation would include only property added from September 11, 2001 through March 31, 2002. Consequently, the fiscal 2002 qualifying additions were split 50/50 between calendar years 2001 and 2002.

Qualifying property additions for the fiscal year ending March 31, 2003 were split 75 % to 2002 and 25% to 2003. At the time of this filing, the Company had not yet filed its federal income tax return for the fiscal year ending March 31, 2003 and as such the actual 2003 fiscal year additions are subject to adjustment. In addition, the Company records current and deferred taxes based on estimated property additions, and as such the calendar year 2003 includes nine months of such estimated qualifying property additions. These estimated property additions will be trued up to actual in next year's exogenous factor filing.

Q. How was the Company's WACC derived?

A. The WACC represents the Capital structure and rates last approved for the Company in Docket D.P.U./D.T.E. 96-25 and is shown on Exhibit MDL-4.

VI. <u>Summary</u>

Q. Would you summarize the results of your analysis with regard to the Bonus Depreciation exogenous factor?

A. The Job Creation and Worker Assistance Act of 2002 resulted in, among other things, an amendment to tax depreciation rules for federal income tax calculation purposes. Specifically, the amendments allowed for a first year bonus depreciation tax deduction for certain qualifying property. As a result of these Bonus Depreciation rules, the Company will realize additional current, or cash, income tax benefits and will record additional deferred taxes. These additional deferred taxes will in turn have a decreasing impact on the Company's rate base upon which the Company earns a return. The Company believes that this economic benefit constitutes an exogenous factor as defined in the Settlement at Section C. As shown on Exhibit MDL-1, the Company estimates this economic benefit at $2,064,714 for calendar year 2003.

VII. Conclusion

Q. Does that conclude your testimony?

A. Yes it does.

Exhibit MDL-1

Summary of Benefit of Bonus Depreciation

Massachusetts Electric Company
Nantucket Electric Company

Exogenous Event - IRC 168(k)
Estimated Rev Req Impact through 12/31/03

Line	(1) Qualifying Property Class	(2) Avg Return Benefit
1)	20 Year Utility Plant Qualifying for 30% Bonus Depreciation	($1,551,496)
2)	20 Year Utility Plant Qualifying for 50% Bonus Depreciation	($435,979)
3)	7 Year Utility Plant Qualifying for 30% Bonus Depreciation	($57,057)
4)	7 Year Utility Plant Qualifying for 50% Bonus Depreciation	($20,182)
	Total	($2,064,714)

Source Notes:
Line 1) From Exhibit MDL - 2, Page 1 (30% Bonus) CY2003, Column (11)
Line 2) From Exhibit MDL - 2, Page 2 (50% Bonus) CY2003, Column (11)
Line 3) From Exhibit MDL - 3, Page 1 (30% Bonus) CY2003, Column (11)
Line 4) From Exhibit MDL - 3, Page 2 (50% Bonus) CY2003, Column (11)

Exhibit MDL-2

Bonus Depreciation – 20 Year Utility Property

Massachusetts Electric Company
Nantucket Electric Company

Exogenous Event - IRC 168(k)
Estimated Rev Req Impact for 20 Year Property @ 30%

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Year	MACRS Tax Depr Rates	IRC 168(k) Tax Depr Rates	Diff	Addition Year	Qualifying Addition Amount	Add'l Def Tax Provision 2001 Additions	Add'l Def Tax Provision 2002 Additions	Add'l Def Tax Provision 2003 Additions	Cumul. Add'l Def Tax Prov	Avg Accum Def Tax	MECO Pre-Tax Return 13.09%
1	3.75%	32.63%	28.88%	2001	$ 11,685,149	$ 1,180,930	$ -	$ -	$ 1,180,930	$ 590,465	$ (77,292)
2	7.22%	5.05%	-2.17%	2002	78,863,247	(88,573)	7,970,117	-	9,062,474	5,121,702	(670,431)
3	6.68%	4.67%	-2.00%	2003	61,940,019	(81,923)	(597,779)	$6,259,813	14,642,585	11,852,530	(1,551,496)
4	6.18%	4.32%	-1.85%			(75,788)	(552,898)	(469,502)	13,544,397	14,093,491	(1,844,838)
5	5.71%	4.00%	-1.71%			(70,095)	(511,495)	(434,252)	12,528,554	13,036,475	(1,706,475)
6	5.29%	3.70%	-1.59%			(64,844)	(473,073)	(401,734)	11,588,904	12,058,729	(1,578,488)
7	4.89%	3.42%	-1.47%			(59,973)	(437,632)	(371,556)	10,719,742	11,154,323	(1,460,101)
8	4.52%	3.17%	-1.36%			(55,482)	(404,758)	(343,721)	9,915,782	10,317,762	(1,350,595)
9	4.46%	3.12%	-1.34%			(54,746)	(374,451)	(317,901)	9,168,684	9,542,233	(1,249,078)
10	4.46%	3.12%	-1.34%			(54,734)	(369,482)	(294,097)	8,450,371	8,809,527	(1,153,167)
11	4.46%	3.12%	-1.34%			(54,746)	(369,399)	(290,195)	7,736,030	8,093,200	(1,059,400)
12	4.46%	3.12%	-1.34%			(54,734)	(369,482)	(290,130)	7,021,684	7,378,857	(965,892)
13	4.46%	3.12%	-1.34%			(54,746)	(369,399)	(290,195)	6,307,343	6,664,513	(872,385)
14	4.46%	3.12%	-1.34%			(54,734)	(369,482)	(290,130)	5,592,997	5,950,170	(778,877)
15	4.46%	3.12%	-1.34%			(54,746)	(369,399)	(290,195)	4,878,656	5,235,827	(685,370)
16	4.46%	3.12%	-1.34%			(54,734)	(369,482)	(290,130)	4,164,310	4,521,483	(591,862)
17	4.46%	3.12%	-1.34%			(54,746)	(369,399)	(290,195)	3,449,969	3,807,140	(498,355)
18	4.46%	3.12%	-1.34%			(54,734)	(369,482)	(290,130)	2,735,623	3,092,796	(404,847)
19	4.46%	3.12%	-1.34%			(54,746)	(369,399)	(290,195)	2,021,283	2,378,453	(311,339)
20	4.46%	3.12%	-1.34%			(54,734)	(369,482)	(290,130)	1,306,936	1,664,110	(217,832)
21	2.23%	1.56%	-0.67%			(27,373)	(369,399)	(290,195)	619,969	963,453	(126,116)
22	0.0%	0.0%	0.00%			-	(184,741)	(290,130)	145,098	382,533	(50,074)
23	0.0%	0.0%	0.00%			-	-	(145,098)	-	72,549	(9,497)
24	0.0%	0.0%	0.00%			-	-	-	-	-	-
25	0.0%	0.0%	0.00%			-	-	-	-	-	-
26	0.0%	0.0%	0.00%			-	-	-	-	-	-
27	0.0%	0.0%	0.00%			-	-	-	-	-	-
28	0.0%	0.0%	0.00%			-	-	-	-	-	-
29	0.0%	0.0%	0.00%			-	-	-	-	-	-
30	0.0%	0.0%	0.00%			-	-	-	-	-	-
31	0.0%	0.0%	0.00%			-	-	-	-	-	-
32											
33											
	100.00%	100.00%	0.00%			$ -	$ -	$ -			

Footnotes:
Column (1) MACRS tax depreciation rates for 20 year utility property
Column (2) MACRS rate adjusted for 30% bonus depreciation allowance: Year 1 = (30% + (70% x MACRS Year 1 Rate)), Years 2-21 = 70% x MACRS Rate from Column (1)
Column (3) Column (2) minus Column (1)
Column (4) Calendar year of qualifying property addition
Column (5) $ value of property additions qualifying for the bonus depreciation allowance by calendar year
Column (6) Column (5) Year 1 x Column (3) Years 1 thru 21 x 35% (Federal Income Tax Rate)
Column (7) Column (5) Year 2 x Column (3) Years 1 thru 21 x 35% (Federal Income Tax Rate)
Column (8) Column (5) Year 3 x Column (3) Years 1 thru 21 x 35% (Federal Income Tax Rate)
Column (9) Column (9) prior year plus the sum of Columns (6), (7) & (8)
Column (10) Column (9) current year plus Column (9) prior year divided by 2
Column (11) Column (10) x 13.09% (MECo Pre-Tax Return Rate)

Massachusetts Electric Company
Nantucket Electric Company

Exogenous Event - IRC 168(k)
Estimated Rev Req Impact for 20 Year Property @ 50%

Year	(1) MACRS Tax Depr Rates	(2) IRC 168(k) Tax Depr Rates	(3) Diff	(4) Addition Year	(5) Qualifying Addition Amount	(6) Add'l Def Tax Provision 2001 Additions	(7) Add'l Def Tax Provision 2002 Additions	(8) Add'l Def Tax Provision 2003 Additions	(9) Cumul. Add'l Def Tax Prov	(10) Avg Accum Def Tax	(11) MECO Pre-Tax Return 13.09%
1	3.75%	51.88%	48.13%	2001	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	7.22%	3.61%	-3.61%	2002	-	-	-	-	-	-	-
3	6.68%	3.34%	-3.34%	2003	39,547,320	-	-	6,661,252	6,661,252	3,330,626	(435,979)
4	6.18%	3.09%	-3.09%			-	-	(499,611)	6,161,641	6,411,446	(839,258)
5	5.71%	2.86%	-2.86%			-	-	(462,101)	5,699,540	5,930,590	(776,314)
6	5.29%	2.64%	-2.64%			-	-	(427,497)	5,272,043	5,485,792	(718,090)
7	4.89%	2.44%	-2.44%			-	-	(395,384)	4,876,659	5,074,351	(664,233)
8	4.52%	2.26%	-2.26%			-	-	(365,763)	4,510,896	4,693,777	(614,415)
9	4.46%	2.23%	-2.23%			-	-	(338,288)	4,172,608	4,341,752	(568,335)
10	4.46%	2.23%	-2.23%			-	-	(312,958)	3,859,650	4,016,129	(525,711)
11	4.46%	2.23%	-2.23%			-	-	(308,805)	3,550,845	3,705,248	(485,017)
12	4.46%	2.23%	-2.23%			-	-	(308,736)	3,242,109	3,396,477	(444,599)
13	4.46%	2.23%	-2.23%			-	-	(308,805)	2,933,304	3,087,706	(404,181)
14	4.46%	2.23%	-2.23%			-	-	(308,736)	2,624,568	2,778,936	(363,763)
15	4.46%	2.23%	-2.23%			-	-	(308,805)	2,315,763	2,470,165	(323,345)
16	4.46%	2.23%	-2.23%			-	-	(308,736)	2,007,026	2,161,395	(282,927)
17	4.46%	2.23%	-2.23%			-	-	(308,805)	1,698,221	1,852,624	(242,508)
18	4.46%	2.23%	-2.23%			-	-	(308,736)	1,389,485	1,543,853	(202,090)
19	4.46%	2.23%	-2.23%			-	-	(308,805)	1,080,680	1,235,083	(161,672)
20	4.46%	2.23%	-2.23%			-	-	(308,736)	771,944	926,312	(121,254)
21	2.23%	1.12%	-1.12%			-	-	(308,805)	463,139	617,541	(80,836)
22	0.0%	0.0%	0.00%			-	-	(308,736)	154,403	308,771	(40,418)
23	0.0%	0.0%	0.00%			-	-	(154,403)	-	77,201	(10,106)
24	0.0%	0.0%	0.00%			-	-	-	-	-	-
25	0.0%	0.0%	0.00%			-	-	-	-	-	-
26	0.0%	0.0%	0.00%			-	-	-	-	-	-
27	0.0%	0.0%	0.00%			-	-	-	-	-	-
28	0.0%	0.0%	0.00%			-	-	-	-	-	-
29	0.0%	0.0%	0.00%			-	-	-	-	-	-
30	0.0%	0.0%	0.00%			-	-	-	-	-	-
31	0.0%	0.0%	0.00%			-	-	-	-	-	-
32											
33											
	100.00%	100.00%	0.00%			$ -	$ -	$ -			

Footnotes:

Column (1) MACRS tax depreciation rates for 20 year utility property
Column (2) MACRS rate adjusted for 50% bonus depreciation allowance: Year 1 = (50% + (50% x MACRS Year 1 Rate)), Years 2-21 = 50% x MACRS Rate from Column (1)
Column (3) Column (2) minus Column (1)
Column (4) Calendar year of qualifying property addition
Column (5) $ value of property additions qualifying for the bonus depreciation allowance by calendar year
Column (6) Column (5) Year 1 x Column (3) Years 1 thru 21 x 35% (Federal Income Tax Rate)
Column (7) Column (5) Year 2 x Column (3) Years 1 thru 21 x 35% (Federal Income Tax Rate)
Column (8) Column (5) Year 3 x Column (3) Years 1 thru 21 x 35% (Federal Income Tax Rate)
Column (9) Column (9) prior year plus the sum of Columns (6), (7) & (8)
Column (10) Column (9) current year plus Column (9) prior year divided by 2
Column (11) Column (10) x 13.09% (MECo Pre-Tax Return Rate)

Exhibit MDL-3

Bonus Depreciation – 7 Year Utility Property

Massachusetts Electric Company
Nantucket Electric Company

Exogenous Event - IRC 168(k)
Estimated Rev Req Impact for 7 year Property @ 30%

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Year	MACRS Tax Depr Rates	IRC 168(k) Tax Depr Rates	Diff	Addition Year	Qualifying Addition Amount	Add'l Def Tax Provision 2001 Additions	Add'l Def Tax Provision 2002 Additions	Add'l Def Tax Provision 2003 Additions	Cumul. Add'l Def Tax Prov	Avg Accum Def Tax	MECO Pre-Tax Return 13.09%
1	14.29%	40.00%	25.71%	2001	$ 2,472	$ 222	$ -	$ -	$ 222	$ 111	$ (15)
2	24.49%	17.14%	-7.35%	2002	3,725,728	(64)	335,299	-	335,458	167,840	(21,970)
3	17.49%	12.24%	-5.25%	2003	3,296,865	(45)	(95,805)	296,703	536,310	435,884	(57,057)
4	12.49%	8.74%	-3.75%			(32)	(68,421)	(84,777)	383,079	459,695	(60,174)
5	8.93%	6.25%	-2.68%			(23)	(48,861)	(60,545)	273,650	328,365	(42,983)
6	8.92%	6.24%	-2.68%			(23)	(34,934)	(43,237)	195,456	234,553	(30,703)
7	8.93%	6.25%	-2.68%			(23)	(34,895)	(30,913)	129,624	162,540	(21,276)
8	4.46%	3.12%	-1.34%			(12)	(34,934)	(30,878)	63,800	96,712	(12,660)
9	0.0%	0.0%	0.0%			-	(17,448)	(30,913)	15,439	39,620	(5,186)
10	0.0%	0.0%	0.0%			-	-	(15,439)	-	7,720	(1,010)
11	0.0%	0.0%	0.0%			-	-	-	-	-	-
12	0.0%	0.0%	0.0%			-	-	-	-	-	-
13	0.0%	0.0%	0.0%			-	-	-	-	-	-
14	0.0%	0.0%	0.0%			-	-	-	-	-	-
15	0.0%	0.0%	0.0%			-	-	-	-	-	-
16	0.0%	0.0%	0.0%			-	-	-	-	-	-
17	0.0%	0.0%	0.0%			-	-	-	-	-	-
18	0.0%	0.0%	0.0%			-	-	-	-	-	-
19	0.0%	0.0%	0.0%			-	-	-	-	-	-
20	0.0%	0.0%	0.0%			-	-	-	-	-	-
21	0.0%	0.0%	0.0%			-	-	-	-	-	-
22	0.0%	0.0%	0.0%			-	-	-	-	-	-
23	0.0%	0.0%	0.0%			-	-	-	-	-	-
24	0.0%	0.0%	0.0%			-	-	-	-	-	-
25	0.0%	0.0%	0.0%			-	-	-	-	-	-
26	0.0%	0.0%	0.0%			-	-	-	-	-	-
27	0.0%	0.0%	0.0%			-	-	-	-	-	-
28	0.0%	0.0%	0.0%			-	-	-	-	-	-
29	0.0%	0.0%	0.0%			-	-	-	-	-	-
30	0.0%	0.0%	0.0%			-	-	-	-	-	-
31	0.0%	0.0%	0.0%			-	-	-	-	-	-
32											
33											
	100.00%	100.00%	0.00%			$ -	$ -	$ -			

Footnotes:
Column (1) MACRS tax depreciation rates for 7 year utility property
Column (2) MACRS rate adjusted for 30% bonus depreciation allowance: Year 1 = (30% + (70% x MACRS Year 1 Rate)), Years 2-8 = 70% x MACRS Rate from Column (1)
Column (3) Column (2) minus Column (1)
Column (4) Calendar year of qualifying property addition
Column (5) $ value of property additions qualifying for the bonus depreciation allowance by calendar year
Column (6) Column (5) Year 1 x Column (3) Years 1 thru 8 x 35% (Federal Income Tax Rate)
Column (7) Column (5) Year 2 x Column (3) Years 1 thru 8 x 35% (Federal Income Tax Rate)
Column (8) Column (5) Year 3 x Column (3) Years 1 thru 8 x 35% (Federal Income Tax Rate)
Column (9) Column (9) prior year plus the sum of Columns (6), (7) & (8)
Column (10) Column (9) current year plus Column (9) prior year divided by 2
Column (11) Column (10) x 13.09% (MECo Pre-Tax Return Rate)

Massachusetts Electric Company
Nantucket Electric Company

Exogenous Event - IRC 168(k)
Estimated Rev Req Impact for 7 Year Property @ 50%

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Year	MACRS Tax Depr Rates	IRC 168(k) Tax Depr Rates	Diff	Addition Year	Qualifying Addition Amount	Add'l Def Tax Provision 2001 Additions	Add'l Def Tax Provision 2002 Additions	Add'l Def Tax Provision 2003 Additions	Cumul. Add'l Def Tax Prov	Avg Accum Def Tax	MECO Pre-Tax Return 13.09%
1	14.29%	57.15%	42.86%	2001	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	24.49%	12.25%	-12.25%	2002	-	-	-	-	-	-	-
3	17.49%	8.75%	-8.75%	2003	2,055,780	-	-	308,352	308,352	154,176	(20,182)
4	12.49%	6.25%	-6.25%			-	-	(88,106)	220,246	264,299	(34,597)
5	8.93%	4.47%	-4.47%			-	-	(62,922)	157,324	188,785	(24,712)
6	8.92%	4.46%	-4.46%			-	-	(44,934)	112,389	134,857	(17,653)
7	8.93%	4.47%	-4.47%			-	-	(32,127)	80,263	96,326	(12,609)
8	4.46%	2.23%	-2.23%			-	-	(32,091)	48,172	64,217	(8,406)
9	0.0%	0.0%	0.0%			-	-	(32,127)	16,045	32,109	(4,203)
10	0.0%	0.0%	0.0%			-	-	(16,045)	-	8,023	(1,050)
11	0.0%	0.0%	0.0%			-	-	-	-	-	-
12	0.0%	0.0%	0.0%			-	-	-	-	-	-
13	0.0%	0.0%	0.0%			-	-	-	-	-	-
14	0.0%	0.0%	0.0%			-	-	-	-	-	-
15	0.0%	0.0%	0.0%			-	-	-	-	-	-
16	0.0%	0.0%	0.0%			-	-	-	-	-	-
17	0.0%	0.0%	0.0%			-	-	-	-	-	-
18	0.0%	0.0%	0.0%			-	-	-	-	-	-
19	0.0%	0.0%	0.0%			-	-	-	-	-	-
20	0.0%	0.0%	0.0%			-	-	-	-	-	-
21	0.0%	0.0%	0.0%			-	-	-	-	-	-
22	0.0%	0.0%	0.0%			-	-	-	-	-	-
23	0.0%	0.0%	0.0%			-	-	-	-	-	-
24	0.0%	0.0%	0.0%			-	-	-	-	-	-
25	0.0%	0.0%	0.0%			-	-	-	-	-	-
26	0.0%	0.0%	0.0%			-	-	-	-	-	-
27	0.0%	0.0%	0.0%			-	-	-	-	-	-
28	0.0%	0.0%	0.0%			-	-	-	-	-	-
29	0.0%	0.0%	0.0%			-	-	-	-	-	-
30	0.0%	0.0%	0.0%			-	-	-	-	-	-
31	0.0%	0.0%	0.0%			-	-	-	-	-	-
32											
33											
	100.00%	100.00%	0.00%			$ -	$ -	$ -			

Footnotes:
Column (1) MACRS tax depreciation rates for 7 year utility property
Column (2) MACRS rate adjusted for 50% bonus depreciation allowance: Year 1 = (50% + (50% x MACRS Year 1 Rate)), Years 2-8 = 50% x MACRS Rate from Column (1)
Column (3) Column (2) minus Column (1)
Column (4) Calendar year of qualifying property addition
Column (5) $ value of property additions qualifying for the bonus depreciation allowance by calendar year
Column (6) Column (5) Year 1 x Column (3) Years 1 thru 8 x 35% (Federal Income Tax Rate)
Column (7) Column (5) Year 2 x Column (3) Years 1 thru 8 x 35% (Federal Income Tax Rate)
Column (8) Column (5) Year 3 x Column (3) Years 1 thru 8 x 35% (Federal Income Tax Rate)
Column (9) Column (9) prior year plus the sum of Columns (6), (7) & (8)
Column (10) Column (9) current year plus Column (9) prior year divided by 2
Column (11) Column (10) x 13.09% (MECo Pre-Tax Return Rate)

Exhibit MDL-4

D.P.U./D.T.E. 96-25 Weighted Average Cost of Capital

Massachusetts Electric Company
Nantucket Electric Company

Cost Of Service
Capital Structure and Cost of Capital
(000)

Line		Balances	Capitalization	Cost Rate	Weighted Return	Taxes	Pre-Tax Return
1)	Long Term Debt	$355,000	43.28%	7.60%	3.29%		3.29%
2)	Preferred Stocks	$50,000	6.10%	6.32%	0.39%	0.25%	0.64%
3)	Common Equity	$415,274	50.63%	11.00%	5.57%	3.59%	9.16%
4)	Total Capitalization	$820,274	100.00%		9.25%	3.84%	13.09%

Source Note:

Above referenced Capital Structure and Rates are based on final Settlement Cost of Service in D.T.E. Docket 96-25

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
D. T. E. No. ___________
Witness: Hager

DIRECT TESTIMONY

OF

MICHAEL J. HAGER

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. Michael J. Hager, 55 Bearfoot Road, Northborough, Massachusetts 01532.

Q. Please state your position.

A. I am the Vice President, Energy Supply – New England for National Grid USA Service Company. I am responsible for, among other things, all power procurement and related activities for the distribution companies of National Grid USA (formerly the New England Electric System) including Massachusetts Electric Company ("Mass. Electric") and Nantucket Electric Company ("Nantucket") (together "the Company"). These activities include the procurement of power for Standard Offer Service and Default Service.

Q. Will you describe your educational background and training?

A. In 1982, I graduated from the University of Hartford with a Bachelor of Science degree in Mechanical Engineering. In 1986, I received a Master of Science degree in Mechanical Engineering from Northeastern University. I am a Licensed Professional Engineer in the Commonwealth of Massachusetts.

Q. What is your professional background?

A. From 1982 to 1992, I was employed by New England Power Service Company in various engineering positions. In these positions, I provided support to New England Power

Company's ("NEP") thermal and hydroelectric generating plants with overall responsibility for the management and control of studies and projects from initiation to completion.

From 1992 to 1997, I was employed by NEP where I conducted wholesale and retail power marketing activities involving the sale and purchase of generation resources to and from investor-owned utilities, municipalities, independent power producers, government agencies, brokers, marketers, and end-use retail customers.

In June 1997, I was promoted to the position of Standard Offer Portfolio Manager for New England Power Service Company (now National Grid USA Service Company). In November 2000, my title was changed to Manager, Distribution Energy Services to more fully reflect the scope of work performed by my department.

In April 2002, I was promoted to the position of Director, Energy Supply – New England and took on the added responsibilities of completing the divestiture of NEP's residual generation related interests. In December 2002, I was promoted to the position of Vice President, Energy Supply – New England.

Q. Have you previously testified before the Massachusetts Department of Telecommunications and Energy (the "Department")?

A. Yes.

II. Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Company's filing which seeks to recover certain costs relating to its obligation to provide Standard Offer Service and Default Service that the Company is incurring outside of its power supply contracts. My testimony provides background information on several statutory and regulatory requirements as well as changes that have occurred in the rules governing the wholesale power markets that have resulted in the Company incurring additional costs to supply Standard Offer Service and Default Service that are above and beyond the costs incurred under its power supply contracts. The costs relate to (i) the New England Power Pool Generation Information System ("NEPOOL GIS"), (ii) the Massachusetts Renewable Portfolio Standards ("RPS") and (iii) the implementation of the New England Power Pool ("NEPOOL") Standard Market Design ("SMD"). Exhibit MJH-1 presents the amounts incurred to date in more detail, and the testimony of Ms. Theresa M. Burns discusses the Company's proposal for recovering these costs.

III. NEPOOL Generation Information System

Q. What is the NEPOOL GIS?

A. The NEPOOL GIS is an accounting system that was designed to track various characteristics or "attributes" of electric generation within NEPOOL. Tracking is accomplished through the creation and trading of certificates. All load and generation within NEPOOL is accounted for in the NEPOOL GIS.

Q. What are certificates?

A. Certificates are electronic records created within the NEPOOL GIS that are associated with the generation of electricity. A certificate is created for each megawatt-hour ("MWh") of electricity that is produced and contains information that includes, but is not limited to, the identification of the specific generation facility that produced the power, the type of fuel used, emissions characteristics of the generation and whether the generation qualifies for various state programs (such as the Massachusetts Renewable Portfolio Standard).

Q. Why was the NEPOOL GIS created?

A. The NEPOOL GIS was created as a mechanism to enable market participants (generators, retail suppliers, regulators, etc.) to demonstrate compliance with various public policy mandates such as labeling requirements, verification of marketing claims, renewable portfolio standards and emission portfolio standards.

Q. When was the NEPOOL GIS implemented?

A. In 2000, NEPOOL established a working group to explore the idea of establishing the NEPOOL GIS and obtained approval from the NEPOOL Participants Committee to proceed. In 2001, NEPOOL issued a Request For Proposal seeking a third party to develop and implement the NEPOOL GIS in accordance with rules that are established by NEPOOL. The NEPOOL GIS became operational in 2002 with the creation and tracking of certificates for generation as of January 1, 2002.

Q. Who runs the NEPOOL GIS?

A. The NEPOOL GIS is run by APX Inc. ("APX") under contract to NEPOOL.

Q. What are the costs of operating the NEPOOL GIS?

A. Under the agreement between NEPOOL and APX, APX is paid a per-MWh fee for each certificate that is created as well as traded in the NEPOOL GIS. Based on costs billed by the Independent System Operator-New England ("ISO-NE") for the period January 2003 through June 2003, the cost of operating the NEPOOL GIS is approximately $2.2 million per year.

Q. Who pays the costs of operating the NEPOOL GIS?

A. NEPOOL has adopted a cost allocation methodology, a copy of which is provided in Exhibit MJH-2. In general, the costs of operating the NEPOOL GIS are allocated to retail load that is subject to "Attribute Laws" which are defined in the cost allocation document as:

> "Attribute Laws" are any statutes, regulations or orders or decisions of courts and governmental agencies in effect in New England requiring (i) the disclosure of the fuel source, emissions and/or other attributes of the generation used in providing electric service to retail customers, (ii) the inclusion of specified amounts of generation with particular attributes in the generation used in providing electric service to retail customers, and/or (iii) that generation falling within specified emission limits be used to serve retail customers. The Attribute Laws as of March 8, 2002 include, but are not necessarily limited to, those set forth on Appendix A [to the NEPOOL GIS cost allocation document]. Not all retail load serving entities in a state with an Attribute Law are necessarily subject to that Attribute Law."

Q. Is the cost allocation methodology pursuant to a FERC approved rate schedule?

A. Yes. On October 26, 2001, NEPOOL filed the Eightieth Agreement Amending New England Power Pool Agreement (the "Eightieth Agreement") with FERC. The Eightieth Agreement revised the Restated NEPOOL Agreement and the NEPOOL Billing Policy to address the allocation and payment of the costs incurred for the development, implementation and ongoing operation and administration of the NEPOOL GIS. The filing noted that the allocation and payment of the NEPOOL GIS-related expenses among the NEPOOL Participants will be made at the direction of the NEPOOL Participants Committee and that the NEPOOL Participants Committee had placed this issue on the agenda for an upcoming meeting and would provide FERC with information describing its determination after it is made.

Q. When was this cost allocation methodology adopted?

A. The NEPOOL Participants Committee approved the cost allocation methodology on June 21, 2002.

Q. Has the Company been assessed any costs of the NEPOOL GIS to date as a result of its provision of Standard Offer Service and Default Service?

A. Yes. The load associated with the Company's provision of Standard Offer Service and Default Service is subject to Attribute Laws through (i) the requirement to provide label/disclosure information to customers pursuant to 220 CMR 11.06 and (ii) the requirement to comply with the RPS beginning in January 2003. Under the NEPOOL cost allocation rules, ISO-NE assessed these costs to the Company prior to the implementation of SMD. Since the implementation of SMD, the costs have been assessed to both the Company and its suppliers depending on how the Company's contracts were implemented within the NEPOOL market settlement system.

Q. How much has the Company incurred in NEPOOL GIS costs to date?

A. The Company has incurred approximately $861,000 in NEPOOL GIS costs related to its Standard Offer Service and Default Service load through September 2003. However, in its *January 2003 Retail Rate Filing* in Docket D.T.E. 02-79, submitted to the Department on November 27, 2002, the Company stated that since it did not have a mechanism in place at the time to recover the costs incurred through September 2002 of approximately $534,000, it would not seek to recover that amount. Therefore, for the 12-month period October 2002 through September 2003, the Company has incurred an additional $327,000, as shown in Exhibit MJH-3. This amount, when taken with the Renewable Portfolio Standards renewable energy certificates purchased by the Company through September 2003 (discussed below), exceeds the $1 million threshold for exogenous factor recovery, as discussed in more detail by Ms. Burns.

Q. Do you believe the development of the NEPOOL GIS was directly related to the implementation of the Massachusetts RPS?

A. Yes. While the NEPOOL GIS system may have been developed at a later date to meet other requirements, I believe the impetus for its initial creation was the implementation of the Massachusetts RPS.

IV. Massachusetts Renewable Portfolio Standards

Q. Why was the Massachusetts RPS initiated?

A. The Electric Utility Restructuring Act of 1997[1] established a requirement to foster the development of new renewable energy sources through implementation of the Renewable Portfolio Standard ("RPS") (M.G.L. ch. 25A, § 11F). The Act required the Division of Energy Resources ("DOER") to promulgate rules to implement the RPS requirements which include, beginning in 2003, the requirement that all retail electricity suppliers source a minimum portion of their resources from certain new renewable energy resources.

Q. Was the Company considered a "retail electricity supplier" under the terms of the Act?

A. The Company believes that its obligation to provide Standard Offer Service and Default Service did not subject it to the requirements imposed upon a retail electricity supplier under the Act. In the Act, the legislature plainly distinguished regulated electric companies from competitive retail suppliers. In brief, the former are obligated to provide distribution, default, and standard offer services under regulation by the Department.

[1] Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein, Chapter 164 of the Acts of

Electric companies are specifically excluded from the definition of "supplier," which is "any supplier of generation service to retail customers, including power marketers, brokers, and marketing affiliates of distribution companies, except that no electric company shall be considered a supplier."[2] Thus, although Section 50 of the Act, codified in part as M.G.L. c. 25A, §11F, sets up the renewable portfolio standard, there is no indication that distribution companies such as the Company were considered among those "retail electricity suppliers selling electricity to end-use customers in the commonwealth," to whom the provision applied. On the contrary, the meaning and intent of that provision are clear on their face and also when read in the context of the overall statute and suggest that the RPS requirements were not intended to apply to distribution companies by virtue of their Standard Offer Service or Default Service obligations. While electric companies do sell power to end use customers, it is clear from the Act as a whole that they are not considered retail electricity suppliers of electricity. Thus, the Company does not believe the intent of the Act was to have the renewable portfolio standard apply to it nor to its provision of Standard Offer Service or Default Service.

Q. Are the Company's Standard Offer Service and Default Service loads subject to the RPS?

1997 (the "Act").
[2] M.G.L. c. 164, § 1 (emphasis added)

A. Yes. Under the regulations promulgated by the DOER (225 CMR 14.00), the Company, as the provider of Standard Offer Service and Default Service, is required to comply with the RPS requirements.

Q. When were the DOER regulations promulgated?

A. The DOER regulations were promulgated on April 26, 2002.

Q. What obligations do the RPS regulations impose upon the Company?

A. The RPS regulations require the Company to demonstrate that a minimum percentage of its resources that are used to provide Standard Offer Service and Default Service are provided from new renewable energy resources, as such are defined in the regulations. The Company may satisfy this requirement by providing attribute certificates from the NEPOOL GIS, contracting for the output of new renewable energy resources, or making an Alternative Compliance Payment to the Massachusetts Technology Park Corporation. The minimum requirement is 1% for 2003, increasing 0.5% per year until 2009 and increasing 1.0% per year thereafter until DOER elects to suspend the increase.

Q. How has the Company complied with the RPS requirements?

A. On November 1, 2002, the Company filed its Renewable Energy Portfolio Compliance Plan ("Compliance Plan") with the Department in Docket Nos. D.T.E. 99-60 and D.T.E. 00-67. A copy of the Compliance Plan is provided in Exhibit MJH-4. In general, under the Compliance Plan the Company will meet its Standard Offer Service RPS requirements through a combination of bilateral market purchases of certificates and payment of the Alternative Compliance Payment. For its Default Service load, the Company asks potential suppliers of Default Service to quote the costs of certificates in their proposals to serve to the load. The Company evaluates the certificate proposals made by winning Default Service bidders, and chooses the option that is reasonably calculated to reduce overall costs to customers (i.e., included in the Default Service supply purchase, purchase from the bilateral market, or the making of Alternative Compliance Payments).

Q. How much has the Company incurred in Massachusetts RPS costs to date for Standard Offer Service?

A. The Company has incurred approximately $1.9 million in Standard Offer Service-related RPS costs through September 2003, as shown in Exhibit MJH-3. This amount does not include the costs of certificates for which the Company has contracted but has not yet received or paid. The Company has estimated the cost of compliance with the RPS regulations, assuming it had to rely entirely on the Alternate Compliance Payment, to be approximately $7 million for 2003 and approximately $11 million for 2004. Through its Compliance Plan, the Company is able to comply with the RPS requirements at a lower cost than had it relied solely on the making of Alternative Compliance Payments.

Q. How does the Company recover its costs of RPS compliance related to its Default Service obligations?

A. The Department has previously ruled that a portion of these RPS costs, i.e., the cost of procuring Default Service-related certificates, should be reflected directly in the Default Service rates charged to Default Service customers. Since November 2002, the Company has included an estimate of the procurement cost of certificates in its Default Service rates, and thus has been recovering a portion of the Default Service RPS compliance costs in rates. As described in Ms. Burns' testimony, the Company also recently filed to amend its Default Service Adjustment Provision to reconcile its Default Service-related costs of acquiring certificates or making Alternative Compliance Payments with Default Service revenues. Because the recovery of certificate and Alternative Compliance Payment costs for Default Service is provided for directly in the Default Service rate (and the proposed adjustment provision), the Company is not seeking recovery of those particular costs as part of this exogenous factor filing. However, the NEPOOL GIS costs related to Default Service RPS compliance are not currently recovered in the Default Service rate or proposed to be recovered under the Default Service Adjustment Provision, and therefore these costs are appropriate for recovery as an exogenous factor.

Q. Is the Company required to utilize the NEPOOL GIS to meet it RPS requirements?

A. Yes. The DOER's regulations require the Company to utilize the NEPOOL GIS to demonstrate compliance with the RPS requirements.

V. <u>NEPOOL Standard Market Design</u>

Q. What is the NEPOOL Standard Market Design ("NEPOOL SMD")?

A. NEPOOL SMD is the set of market rules that govern the operation of the wholesale power markets in New England.

Q. When were the SMD rules developed by NEPOOL?

A. In July 2002, NEPOOL filed its SMD proposal at the Federal Energy Regulatory Commission ("FERC"), which included its proposed congestion management system rules. On September 20, 2002, FERC approved NEPOOL's SMD proposal, permitting it to go into effect once market trials demonstrated that the system was ready to be implemented.

Q. When did NEPOOL implement its SMD system?

A. The NEPOOL SMD system began on March 1, 2003.

Q. Has the introduction of SMD affected the implementation of the Standard Offer Service agreements?

A. Yes. NEPOOL's SMD was a significant redesign of the market rules. The two most significant contract implementation issues that arose because of SMD relate to (1) responsibility for congestion costs and (2) the specification of delivery points and responsibilities of the buyer and seller beyond the delivery points.

Q. How has the allocation of congestion costs changed with the implementation of NEPOOL SMD?

A. The treatment of congestion costs has been a subject of discussion within NEPOOL since at least 1996. In December 1996, NEPOOL filed a comprehensive restructuring proposal with FERC. At that time, NEPOOL members believed that there was relatively little congestion in New England, but recognized the need to address the potential for congestion. Given these circumstances, NEPOOL agreed conceptually in 1996 to a methodology for assigning congestion costs to suppliers of load, but deferred development of its details.

Faced with the need to address other issues associated with its restructuring, NEPOOL members did not agree in 1997 on a methodology for assigning congestion costs to suppliers of load. Instead, in an October 31, 1997 filing with FERC, NEPOOL proposed an interim mechanism for spreading congestion costs across the entire Pool through the end of 1999. NEPOOL accomplished this objective by providing that congestion costs be paid as a transmission charge and included in the charge for Regional Network Service ("RNS").

NEPOOL's assignment of congestion costs to RNS originally was supposed to remain in effect only through the end of 1999. Thereafter, NEPOOL planned to assign congestion costs under market operation rules to be adopted later. In March 1999, NEPOOL submitted a preliminary proposal for a congestion management system based conceptually on nodal/zonal prices, which FERC accepted. NEPOOL was unable, however, to agree on a final congestion management system in 1999 and sought a 60-day extension of the period under which the assignment of congestion costs to RNS would be in effect. FERC granted that extension as well as two others in 2000.

In July 2002, NEPOOL filed its SMD proposal at FERC, which included its proposed congestion management rules. Under this SMD proposal, NEPOOL would be divided into separate zones, each having its own zonal price. Congestion costs would be borne by suppliers of load in congested zones and reflected in the difference in prices between zones: a higher cost zone (a congested zone) and a lower cost zone (a zone with less or no congestion). This change reallocated congestion costs from transmission to supply. As a result, the Company's transmission costs have declined and this decline has been reflected in lower transmission charges to the Company's customers; however, the commodity supply costs have increased as the congestion costs have been reallocated to the commodity component of the service. This reallocation has increased the cost of supplying wholesale Standard Offer Service. Under some of the Company's wholesale Standard Offer Service contracts, suppliers have suggested that these higher Standard Offer Service costs are billable to the Company.

Q. Would you provide additional detail on the changes to the Company's cost of procuring its Standard Offer Service supply as a result of the implementation of NEPOOL SMD?

A. The changes in costs that are billed depend on the specific terms and interpretation of the Company's contracts. For the most part, the Company's Standard Offer Service suppliers have implemented their Standard Offer Service contracts within the NEPOOL market settlement system in a manner that has not resulted in the reallocation of any costs to the Company. However, three of the Company's suppliers have claimed that under the terms of their respective Standard Offer Service supply contracts, the Company is responsible for certain costs incurred because of the change in market design resulting from NEPOOL SMD. As a result of how these suppliers have implemented their contracts within the NEPOOL market system, the Company has incurred some additional costs under these Standard Offer Service contracts. The Company also entered into a contract amendment with a fourth supplier under which the supplier would implement the contract consistent with the Company's expectations in return for a modest increase in the contract price.

Q. Please describe the incremental costs that the Company has incurred as a result of the implementation of NEPOOL SMD.

A. The Company has entered into a confidential implementation agreement with one supplier whereby the supplier and the Company agreed to temporarily bear certain costs that they believe the other is responsible for under the terms of the applicable Standard Offer Service contract until a final resolution of the parties' respective obligations can be obtained. To date, the Company has not been billed, either by the supplier or by ISO-NE, for any incremental costs.

A second supplier has unilaterally implemented its Standard Offer Service contract within the NEPOOL market settlement system in a manner that has resulted in the

Company being billed by ISO-NE for certain post-SMD costs. The Company contends that the supplier is responsible for all of the costs billed to it by ISO-NE. The supplier has agreed that it is responsible for some of the costs and claims the Company is responsible for some of the costs. The Company has deducted all of the costs billed to it by ISO-NE from the amounts that it otherwise owed and paid to the supplier. The Company has been billed by ISO-NE approximately $1.5 million in Standard Offer Service-related costs through September 2003 related to this supplier, as shown in Exhibit MJH-5.

A third supplier has alleged that the Company is responsible for congestion costs under the terms of its Standard Offer Service contract and has unilaterally implemented its Standard Offer Service contract within the NEPOOL market settlement system in a manner that has resulted in the Company being billed by ISO-NE for certain costs. These costs include, but are not limited to, post-SMD congestion costs. The Company has paid ISO-NE for the costs that have been billed and has requested reimbursement from the supplier for such amounts. To date, the supplier has not reimbursed the Company for such amounts. The responsibility for congestion costs was resolved via a formal dispute resolution process under which the Company believes the result places responsibility for congestion costs on the supplier. The supplier disagrees. As a result, the Company has sought a confirmation in Superior Court of the dispute resolution decision and award. The Company does not know when the Court will rule, however, oral arguments are currently scheduled for December 2003. The Company has been billed by ISO-NE approximately $1.2 million in Standard Offer Service-related costs through September 2003 related to these disputed costs. This amount is also shown in Exhibit MJH-5.

In regard to the fourth supplier and as explained in more detail in the Company's February 27, 2003 filing in Docket D.T.E. 97-94, a copy of which is provided in Exhibit MJH-6, the Company entered into a contract amendment that resolves the implementation issues that arose under the NEPOOL SMD system with that supplier. Under the terms of the amendment, the supplier agreed to implement its Standard Offer Service contract in a manner that is consistent with the Company's expectation and the Company agreed to a modest increase in the contract price. The Company estimated the increased cost to be approximately $3.2 million per year. As shown in Exhibit MJH-7, the Company has incurred approximately $1.8 million through September 2003 related to the contract amendment.

Q. What costs could the Company have incurred had it not entered into the amendment with the fourth supplier?

A. Had the Company not entered into the amendment with the fourth supplier, and the contract implemented in accordance with the supplier's interpretation of the contractual obligations, the Company estimates it would have incurred approximately $5.6 to $8.3 million in congestion costs from March 2003 through September 2003 under the supplier's Standard Offer Service supply contract.

Q. Has the amendment to the Standard Offer Service contract with the fourth supplier been accepted by FERC?

A. Yes. The amendment, as was the original Standard Offer Service contract, was made pursuant to the supplier's market based rate tariff on file with FERC. Under such tariffs, FERC does not require that each transaction executed pursuant to the tariff be filed with FERC before it is effective. Such transactions are effective upon execution. FERC does require that all sales under such tariffs be reported in the seller's electronic quarterly report to FERC. The supplier commenced reporting the amendment to FERC with its first quarterly report to FERC in 2003.

Q. Is the Company continuing to seek to have the suppliers discussed above bear these disputed costs?

A. Yes. Contractual terms vary among suppliers. In the Company's view, the contracts make Standard Offer Service suppliers responsible for the disputed costs. The Company will continue to seek to have these suppliers bear the costs that arise from the SMD rule changes under the provisions of the contracts. However, since the Company has incurred costs resulting from the SMD rule change, those costs qualify as an exogenous factor under the Company's rate plan settlement governing its merger with Eastern Edison Company in Docket D.T.E. 99-47. Consequently, the Company seeks recovery of those costs without prejudice to its contractual rights. In the event that the resolution of those contractual issues (through arbitration, settlement, or otherwise) changes the amount of the costs that the Company must contractually bear, then these changes will be reconciled as described by Ms. Burns in her testimony.

VI. Summary

Q. Can you please summarize the costs incurred by the Company related to the above exogenous factor events?

A. The Company has incurred approximately $6,7 million to date related to the exogenous factors described above, but, as shown in Exhibit MJH-1, is currently seeking recovery of $5.2 million, because the Company has thus far been able to offset $1.5 million of these costs against its other supply contract obligations.

Q. Does this conclude your testimony?

A. Yes. It does.

Exhibit MJH-1

Summary of Standard Offer Service Costs to be Included in Exogenous Factor

Massachusetts Electric Company
Nantucket Electric Company

Summary of Standard Offer Service Costs
To Be Included in Exogenous Factor Recovery

		Incurred to Date
(1)	RPS Compliance Costs	$2,207,110
(2)	SMD Costs	$1,144,455
(3)	Congestion Costs	$1,832,992
(4)	Total	$5,184,557

(1) Exhibit MJH-3
(2) Exhibit MJH-5
(3) Exhibit MJH-7
(4) Sum of Lines (1) through (3)

Exhibit MJH-2

NEPOOL GIS Cost Allocation Methodology

NEPOOL PARTICIPANTS COMMITTEE
6/21/02 MEETING, AGENDA ITEM #_

Attachment 1

Allocation of Costs Related to Generation Information System

1. **Definitions**

Capitalized terms not otherwise defined herein have the meanings given to them in the Restated NEPOOL Agreement (including the Restated NEPOOL Open Access Transmission Tariff and the Market Rules and Procedures).

"Attribute Laws" are any statutes, regulations or orders or decisions of courts and governmental agencies in effect in New England requiring (i) the disclosure of the fuel source, emissions and/or other attributes of the generation used in providing electric service to retail customers, (ii) the inclusion of specified amounts of generation with particular attributes in the generation used in providing electric service to retail customers, and/or (iii) that generation falling within specified emission limits be used to serve retail customers. The Attribute Laws as of March 8, 2002 include, but are not necessarily limited to, those set forth on Appendix A hereto. Not all retail load serving entities in a state with an Attribute Law are necessarily subject to that Attribute Law.

"GIS Load" for any GIS Participant is, for any month, the sum of the meter readings in such month for all GIS Load Assets owned by that GIS Participant.

A "GIS Load Asset" is any Load Asset registered with the System Operator which (x) is owned by a Participant that either is subject to an Attribute Law with respect to that specific Load Asset, or (y) is owned by a Participant that supplies power for that Load Asset directly to a non-Participant that is in turn subject to an Attribute Law with respect to that specific Load Asset, or (z) is owned by a Participant that supplies power for that Load Asset directly to a Participant that is in turn subject to an Attribute Law with respect to that specific Load Asset; provided, however, that any GIS Load Asset owned by a Participant that supplies power for that Load Asset directly to a Participant that is in turn subject to an Attribute Law with respect to that specific Load Asset, as described in clause (z) above, shall, for purposes of determining the amount of GIS Costs that are attributable to Participants hereunder, be deemed to be owned by the Participant that is subject to an Attribute Law with respect to that Load Asset. Each Load Asset shall be presumed to be a GIS Load Asset unless it is identified otherwise pursuant to the provisions of section 2 below.

A "GIS Participant" is any Participant that owns one or more GIS Load Asset(s). No Governance Only Member will be deemed to be a GIS Participant.

"GIS Costs" are all of the expenses incurred by NEPOOL in any given month in connection with its generation information system, including without limitation all amounts payable by

NEPOOL to the entity or entities that develop, administer, operate and maintain that generation information system and to the project manager for that generation information system.

"Subcommittee" is the NEPOOL Budget and Finance Subcommittee or any other group or committee designated by the Participants Committee to serve the functions of the Subcommittee hereunder.

2. Identification of GIS Load Assets

a) Every Load Asset will be deemed to be a GIS Load Asset, subject to the allocation and payment procedures described herein, unless the Participant that owns that Load Asset certifies to the Subcommittee, in accordance with this section 2, that such Load Asset is not a GIS Load Asset.

b) To demonstrate that any Load Asset owned by it is not a GIS Load Asset, on an annual basis and whenever the Subcommittee or the System Operator deems necessary, a Participant shall provide the Subcommittee, either a certification by an officer of that Participant (a "Certification") or an opinion of counsel to that Participant (an "Opinion") explaining the specific reason or reasons why such Load Asset is not a GIS Load Asset; provided, however, that the System Operator or the Subcommittee may specifically require a Participant claiming any Load Asset is not a GIS Load Asset to provide either a Certification or an Opinion. Each such Certification or Opinion shall include, for each Load Asset covered thereby, an asset identification number, the state in which the load associated with that Load Asset is situated, and the specific reason why such Load Asset is not a GIS Load Asset. Conclusory statements that a Load Asset is not a GIS Load Asset without an adequate explanation shall not satisfy the requirements of this provision. The Subcommittee shall periodically provide the System Operator with a list of the Load Assets, by asset identification number, which have been demonstrated to the satisfaction of the Subcommittee not to be GIS Load Assets.

c) Beginning with the month immediately before the first month in which the System Operator begins billing and collecting GIS Costs based on this procedure, the certification or opinion of counsel described in paragraph (b) above must be provided by a Participant to the Subcommittee by the 20th day of the month in order for that Participant to avoid being allocated a portion of the GIS Costs in the following month, and subject to paragraph (d) below, all subsequent months of that same calendar year in which the Participant does not own any GIS Load Assets. Participants that do not own Load Assets are not required to submit an Opinion or

Certification. In addition, each Participant that owns a Load Asset and expects not to be charged a portion of the GIS Costs under this procedure shall provide its Certification or Opinion to the Subcommittee by July 20, 2002, if it has not already done so.

d) Each Participant shall notify the Subcommittee immediately if any Load Asset owned by it becomes a GIS Load Asset as a result of either a change in law or a change in the nature of such Load Asset.

e) The System Operator will periodically (and no less frequently than annually) publish to all of the Participants and to the utility regulatory agencies in each of the New England states (via the System Operator's website and/or direct electronic mail) a listing, by asset identification number, owning Participant and state, of all of the GIS Load Assets and all of the Load Assets that are not GIS Load Assets. That listing will also identify the Load Assets that are related solely to station service.

f) Any Participant may challenge whether a Load Asset is a GIS Load Asset by requesting that the Participants Committee find that such Load Asset is or is not a GIS Load Asset, including in such request the specific reasons for its challenge. Any finding to such effect by the Participants Committee shall be subject to the usual voting and appeal requirements with respect to actions by the Participants Committee.

3. **Allocation of Costs to GIS Participants**

The amount of GIS Costs being allocated on a GIS Participant's bill in any month will be based on its GIS Load in the previous month. This monthly allocation of GIS Costs to each GIS Participant ("Participant GIS Cost") will be calculated as follows:

$$\textit{Participant GIS Cost} = \textit{GIS Costs} * \frac{\textit{GIS Load of that GIS Participant}}{\Sigma\ \textit{(GIS Loads of all GIS Participants)}}$$

b) Except in the case of a potential error made in the allocation of any month's GIS Costs that is initially identified to the System Operator within 90 days of the initial allocation, the allocation of the GIS Costs among the GIS Participants in any month will be final and not subject to resettlement.

c) All GIS Costs incurred by NEPOOL and paid by the Participants prior to the effectiveness of the procedure set forth herein, together with interest accrued thereon, will be allocated among the GIS Participants and paid by the GIS Participants to the Participants initially paying such GIS Costs in the first month in which GIS Costs are allocated according to the procedure set forth herein.

Appendix A

Attribute Laws

Connecticut
Conn. Gen. Stat. §16-6c
Conn. Gen. Stat. §16-245a
Conn. Gen. Stat. §16-245p
Conn. Gen. Stat. §22a-174j;
Conn. Agencies Regs. §16-245-5

Maine
Me. Rev. Stat. Ann. §3210
Code Me. R. §65-407-306

Massachusetts
Mass. Gen. L. ch. 25A, §11D
Mass. Gen. L. ch. 25A, §11F
Mass. Gen. L. ch. 111, §142N
Mass. Regs. Code tit. 220, §11.06

New Hampshire
No Attribute Laws at this time

Rhode Island
R.I. Code R. §90 070 004, App., Part F

Vermont
No Attribute Laws at this time

Exhibit MJH-3

RPS Compliance Costs

Massachusetts Electric Company
Nantucket Electric Company

RPS Compliance Costs
September 2002 - Present

	Date	Vendor	Standard Offer Related Renewable Energy Certificates Payment	Description	GIS Assessment	Total
September 2002	09/13/2002	Supplier 1	$30,060.00	2003 certificates		$30,060.00
October	10/04/2002	Supplier 2	$2,104.20	commission	$53,496.65	$55,600.85
November			$0.00		$54,913.78	$54,913.78
December	12/04/2002	Supplier 2	$22,309.49	commission	$57,200.59	$601,184.08
	12/05/2002	Supplier 1	$81,459.00	2003 certificates		
	12/05/2002	Supplier 3	$237,248.00	2003 certificates		
	12/10/2002	Supplier 4	$92,967.00	2003 certificates		
	12/10/2002	Supplier 4	$110,000.00	2003 certificates		
January 2003			$0.00		$64,733.33	$64,733.33
February	02/04/2003	Supplier 2	$7,700.00	commission	$63,086.54	$70,786.54
March	03/04/2003	Supplier 4	$412,248.00	2003 certificates	$5,260.40	$417,508.40
April	04/03/2003	Supplier 2	$8,489.25	commission	$4,846.96	$13,336.21
May	05/16/2003	Supplier 3	$242,550.00	2003 certificates	$4,141.52	$568,771.52
	05/19/2003	Supplier 4	$322,080.00	2003 certificates		
June	06/30/2003	Supplier 5	$9,423.75	commission	$5,456.83	$14,880.58
July			$0.00		$4,068.82	$4,068.82
August	08/19/2003	Supplier 4	$240,000.00	2003 certificates	$4,921.71	$306,504.21
	08/21/2003	Supplier 5	$59,500.00	2003 certificates		
	08/21/2003	Supplier 5	$2,082.50	commission		
September			$0.00		$4,761.84	$4,761.84
		Total To Date	$1,880,221.19		$326,888.97	$2,207,110.16

Source: Invoices relating to the purchase of RECs for Standard Offer Service.
ISO-NE invoice for Standard Offer Service and Default Service.

Note: Supplier names are not provided due to the confidentiality of the information.

Exhibit MJH-4

Mass. Electric's November 1, 2002 RPS Compliance Plan

Massachusetts Electric
A National Grid Company

Amy G. Rabinowitz
Counsel

November 1, 2002

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Renewable Energy Portfolio Compliance Plan; D.T.E. 99-60 and 00-67

Dear Secretary Cottrell:

On behalf of Massachusetts Electric Company and Nantucket Electric Company (collectively "Companies"), I am enclosing for filing the Companies' plan for complying with the renewable portfolio standard ("RPS") established in M.G.L. c. 25A, § 11F and 225 C.M.R. 14.00. This plan encompasses both the Companies' standard offer and default service loads. In addition, I am enclosing revised tariffs (both marked to show changes and clean versions) for the Companies' Standard Service Cost Adjustment Provision and Default Service Adjustment Provision. The Companies have revised these tariffs to include the estimated costs of complying with RPS. The Companies respectfully request approval of these revised tariffs.

For standard offer service, the Companies propose to include the estimated cost of RPS compliance in the Standard Offer Service Fuel Adjustment ("SOSFA") factor. Recovery through the SOSFA factor reflects the fact that RPS compliance increases the commodity costs for standard offer service above the base cost of standard offer procurement. Any difference between the revenue received from standard offer customers and the actual cost of procuring standard offer service, including those of RPS compliance, will flow through the Companies' standard offer reconciliation, and, upon Department approval, be reflected in the Standard Offer Adjustment Factor. Any incremental charge to the SOSFA relating to RPS compliance would fall outside of the mandatory rate reductions required under the Restructuring Act of 1997.

For default service, the Companies propose to include the costs of compliance in the default service rates charged to their default service customers. The rates will initially reflect the Companies' purchased power costs including their estimated costs of RPS compliance. Any difference between the revenue received from default service customers and the actual cost of procuring default service, including the cost of RPS compliance, will flow through the Companies' default service reconciliation and, upon approval of the Department, be reflected in the Companies' Default Service Adjustment Factor.

25 Research Drive
Westborough, MA 01582-0099
Phone 508.389.2975
Fax: 508.389.2463
amy.rabinowitz@us.ngrid.com

Thank you very much for your time and attention to this matter.

Very truly yours,

Amy G. Rabinowitz

cc: Service Lists, D.T.E. 99-60 and 00-67

Massachusetts Electric Company
Nantucket Electric Company
Renewable Energy Portfolio Compliance Plan

BACKGROUND

The Electricity Restructuring Act of 1997 (the "Act") established a requirement to foster the development of new renewable energy sources through implementation of the Renewable Portfolio Standard ("RPS") (M.G.L. ch. 25A, § 11F). The Act requires, beginning in 2003, all retail electricity suppliers to source a minimum portion of their resources from new renewable energy resources. In 2002, the Massachusetts Division of Energy Resources ("DOER") issued final regulations (225 CMR 14.00) implementing these requirements. For 2003, all retail electricity suppliers are required to demonstrate that at least 1% of their generation supply resources are provided from new renewable energy resources. Retail electricity suppliers may satisfy this requirement by providing attribute certificates from the New England Generation Information System ("NE-GIS"), contracting for the output of new renewable energy resources, or making an Alternative Compliance Payment ("ACP") to the Massachusetts Technology Park Corporation. The ACP rate in 2003 is $50 per MWh, and in subsequent years is equal to the previous year's rate adjusted up or down according to the previous year's consumer price index.

Massachusetts Electric Company and Nantucket Electric Company (together the "Companies") are subject to the RPS requirement relating to the supply for both their Standard Offer and Default Service customers. The Companies estimate their RPS requirement for calendar year 2003 sales to be 173,000 RPS certificates.[1] Assuming this requirement is met entirely through ACPs, this would result in a compliance cost of $8.65 million for the year.[2]

The DOER has provided a list of the generating facilities that have been certified to meet the new renewable energy resource requirement. As of October 8, 2002, 15 facilities have been approved with a combined nameplate capacity of 100 MW. The actual number of usable RPS Certificates from these facilities would vary depending upon actual plant performance. Based on the most recent Energy Information Administration data, the Companies estimate that the total Massachusetts certificate requirements are 425,000 for calendar year 2003, and that the requirement for certificates will probably exceed the number of certificates produced and available for purchase.[3]

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[1] Based on total Standard Offer and Default Service load for the 12-month period ending June 30, 2002 of 17.3 million MWh.

[2] This figure does not include any costs charged to the Companies by ISO New England for the Companies' share of supporting the NE-GIS.

[3] Several of the 15 facilities approved by the DOER are not yet constructed and may not be constructed in 2003. In addition, over half of the approved generation is from two facilities that have operated at only a 10% capacity factor during the past 10 years. Should all 100 MW of certified generation operate at 85% capacity factor for a one year period, the number of RPS certificates created would be approximately 714,000. Should the two largest facilities operate at their historical production level, the number of RPS certificates created would only be approximately 360,000. In addition, generating facilities that create

COMPLIANCE ELEMENTS

Since the Companies do not purchase unit specific power to meet their Standard Offer or Default Service requirements, they will purchase RPS certificates and remit ACPs, if necessary, to comply with the RPS requirements.

The form of RPS certificates that may be purchased includes:

- Certificates that have been issued by the NE-GIS during the current active trading session. These certificates will be issued by the NE-GIS from the final, reported production data of RPS certified facilities. As a result the number of available certificates is firm and known.

- Certificates from the future production of an RPS certified facility. These certificates can either be on a firm or unit-contingent basis. With a firm purchase, the seller would be responsible for delivering a fixed number of certificates regardless of actual plant output. A unit-contingent purchase would be based on actual plant output and the number of certificates purchased would be unknown until after final, reported data is available for the specified facility.

PROCUREMENT PROCESS

Due to the different procurement methods for Standard Offer and Default Service, the Companies will procure their RPS requirements for each of these services separately.

Standard Offer

The Companies propose to use several market-based strategies to meet their RPS requirements associated with Standard Offer.

The primary method the Companies will use is a Request for Proposals ("RFP") process. From time to time, the Companies or their agent will issue a RFP to purchase RPS compliant certificates. In evaluating responses to these RFPs, the Companies will consider their outstanding needs and the offers submitted. The Companies will reject any offers that are at or above the ACP. The Companies will retain the discretion to reject some or all bids below the ACP, and will purchase certificates relating to offers that have not been rejected.

Before, between and after their RFPs, the Companies may receive unsolicited offers to purchase RPS certificates. The Companies will review their outstanding needs

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Massachusetts RPS certificates also qualify for other New England states renewable requirements; therefore, the output of these facilities could be sold to meet requirements in other states and thus not be sold/available for purchase against Massachusetts' requirements.

to determine if additional certificates are required for compliance. If the Companies determine the purchase of additional certificates is needed, they will review the offers to determine whether the price and terms of purchase are acceptable. In reviewing the price, the Companies plan to use the results of their most recent RFP, published market information, offers to sell or purchase on the NE-GIS bulletin board, pricing provided by various brokers, and other sources of market intelligence to establish a market price. The Companies will compare this market price to the offer price, and in their discretion may purchase certificates that the Companies believe are reflective of the then current market price. The Companies reserve their right to reject any and all offers.

Before, between and after their RFPs, the Companies may also receive/make offers from/to the broker market for the purchase of certificates. Sellers may use the broker market because they may be unwilling to participate in the RFP process, believe that the broker has access to a larger group of customers, or desire to remain anonymous when making offers to sell. The Companies will review their outstanding needs to determine if additional certificates are required for compliance and if the offer is reflective of the then current market price. The Companies reserve their right to reject any and all offers. The Companies may purchase those certificates that the Companies believe are reflective of the then current market price.

The Companies will attempt to procure enough certificates to meet their RPS requirements relating to Standard Offer. To the extent the Companies are able to procure more than their Standard Offer RPS requirements through the above process and have not fully met their Default Service RPS requirement, the Companies will utilize the above process to procure additional RPS certificates for Default Service.

To the extent the Companies are not able to fully meet their Standard Offer and Default Service RPS requirements through the above process, the Companies will make an ACP for each RPS requirement for which they have not purchased a certificate.

Default Service

Under current regulations, the Companies procure their Default Service requirements through competitive solicitations every six months. In future solicitations, the Companies will seek to include the RPS compliance obligation as part of the winning suppliers' responsibility.

All solicitations will request that bidders provide Default Service prices excluding the RPS compliance and alternate prices including RPS compliance.[4] The Companies will evaluate the bids and determine the lowest cost supply including the RPS compliance. Before committing to this purchase, the Companies will evaluate the winning supplier's (or suppliers') price adder for providing RPS compliant service. If the cost is at or near the ACP cost, the Companies may procure the non-RPS compliant

[4] For these solicitations, RPS compliance means transferring to the Companies sufficient RPS certificates attributable to the load served by the supplier multiplied by the applicable RPS percentage for the year of service.

Default Service and attempt to purchase RPS certificates at a lower cost through a separate solicitation (as described in detail in below). This will provide the Companies with an opportunity to meet the RPS requirements at a lower cost to customers.

Any RPS requirements not provided by Default Service supplier(s) will first be met with RPS certificates purchased by the Companies that exceed the Companies Standard Offer requirements (as described above). To the extent the Companies are unable to obtain sufficient RPS certificates to meet their RPS requirements, they will make ACPs for the unmet requirements.

The Companies believe that the process outlined above will allow them to comply with the RPS requirements at a reasonable cost to their Standard Offer and Default Service customers. Each purchase of a certificate will be at market, though prices will vary over time by supplier and offer (in all cases, however, the purchase price would not exceed the ACP). By purchasing certificates from a mix of suppliers at different times, the Companies can take advantage of dollar cost averaging to reduce price volatility to its customers, with an opportunity to deliver lower compliance costs.

COST RECOVERY

The Companies will incur costs in administering the RPS, including direct purchase costs of certificates, broker fees, option costs, other costs associated with the procurement of RPS certificates and program implementation, and any ACPs paid to the Massachusetts Technology Park Corporation.

Subject to Department approval, for Default Service, the Companies propose to include the costs of compliance in the Default Service rates charged to their Default Service customers. The rates will initially reflect the Companies' purchased power costs including their estimated costs of RPS compliance. Any difference between the revenue received from Default Service customers and the actual cost of procuring Default Service, including the cost of RPS compliance, will flow through the Companies' Default Service reconciliation and, upon approval of the Department, be reflected in the Companies' Default Service Adjustment Factor.

Also subject to Department approval, for Standard Offer service, the Companies propose to include the estimated cost of RPS compliance in the Standard Offer Service Fuel Adjustment ("SOSFA") factor that they file for January 1, 2003. Recovery through the SOSFA factor reflects the fact that RPS compliance increases the commodity costs for standard offer service above the base cost of standard offer procurement. Any difference between the revenue received from Standard Offer customers and the actual cost of procuring Standard Offer service, including those of RPS compliance, will flow through the Companies' Standard Offer reconciliation, and, upon Department approval, be reflected in the Standard Offer Adjustment Factor. Any incremental charge to the SOSFA relating to RPS compliance would also fall outside of the mandatory rate reductions required under the Act.

The recovery of the cost of RPS compliance discussed above necessitates a revision to two of the Companies' tariff provisions: M.D.T.E. No. 981-A, Standard Service Cost Adjustment Provision[5], and M.D.T.E. No. 987-A, Default Service Adjustment Provision[6]. As part of this compliance report, the Companies are requesting the Department to approve the proposed revisions to these tariff provisions to allow for the recovery of the cost of compliance. Both a clean version of each proposed tariff provision as well as a version that is marked to show changes accompany this compliance report. The tariff changes extend beyond allowing for the recovery of RPS compliance costs and include other payments to Standard Offer Service or Default Service suppliers for procuring power, compliance with future statutes or regulations which may confer an obligation on the Companies that are directly related to providing Standard Offer Service or Default Service, and any other costs reasonably incurred for such service as may be approved by the Department.

[5] M.D.T.E. No 981-A is the currently effective provision for Massachusetts Electric Company. The comparable provision for Nantucket Electric Company is M.D.T.E. No. 423.

[6] M.D.T.E. No 987-A is the currently effective provision for Massachusetts Electric Company. The comparable provision for Nantucket Electric Company is M.D.T.E. No. 424.

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
STANDARD SERVICE COST ADJUSTMENT PROVISION

The Standard Service Cost Adjustment shall adjust rates to customers in accordance with the provisions of the Restructuring Settlement Agreement in Docket D.P.U. /D.T.E. No. 96-25 (Settlement Agreement) that relate to Standard Service. Standard Service Cost Adjustments shall be computed to the nearest thousandth of a cent.

On an annual basis, the Company shall reconcile the revenues billed to retail customers taking Standard Service against the total cost of providing Standard Service, and recover or refund any under or over collections in the following manner:

1. Any Standard Service revenues billed by the Company in excess of the total cost of providing Standard Service shall be accumulated in a reconciliation account, together with interest applied at the same rate as that set forth for interest on customer deposits, shall be credited to all of the Company's retail delivery service customers through a uniform cents per kilowatt-hour credit in the following year.

2. Any Standard Service revenues billed by the Company that are not sufficient to recover the total cost of providing Standard Service shall be accumulated in a reconciliation account, together with interest applied at the same rate as that set forth for interest on customer deposits, shall be recovered by the Company through a uniform cents per kilowatt-hour surcharge applied to the rates for Standard Service, subject to the terms of §I.B(5)(b) of the Settlement Agreement. Any under recovery that remains after the February 28, 2005 end of the transition period shall be recovered from all retail delivery service customers through a uniform cents per kilowatt-hour surcharge not to exceed $0.004 per kilowatt-hour commencing on January 1, 2010.

Should any balance remain outstanding subsequent to the refund or recovery of over or under collections as described above, the Company shall reflect as an adjustment in the current reconciliation period the amount of the outstanding balance.

For purposes of the above reconciliation, Standard Service revenues shall mean all revenue billed to Standard Service customers through the Standard Service rate for the applicable 12-month reconciliation period. The cost of providing Standard Service shall mean the cost incurred by the Company in providing Standard Service, which shall include, but not be limited to, payments to Standard Service suppliers for procuring Standard Service power, compliance with current or future statutes, rules or regulations which confer an obligation upon the Company and that is directly related to the Company's requirement to provide Standard Service, and any other costs reasonably incurred as a result of the Company's provision of Standard Service.

Each adjustment of the prices under the Company's applicable rates shall be in accordance with a notice filed with the Department of Telecommunications and Energy (the Department) setting forth the amount of the increase or decrease and the new Standard Service Cost Adjustment amount. The notice shall further specify the effective date of such adjustment, which shall not be earlier than thirty days after the filing of the notice, or such other date as the Department my authorize.

The operation of this Standard Service Cost Adjustment clause is subject to Chapter 164 of the

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
STANDARD SERVICE COST ADJUSTMENT PROVISION

General Laws.

Effective: January 1, 2003

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
STANDARD SERVICE COST ADJUSTMENT PROVISION

The Standard Service Cost Adjustment shall adjust rates to customers in accordance with the provisions of the Restructuring Settlement Agreement in Docket D.P.U. /D.T.E. No. 96-25 (Settlement Agreement) that relate to Standard Service. Standard Service Cost Adjustments shall be computed to the nearest thousandth of a cent.

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2. Any Standard Service revenues billed by the Company that are not sufficient to recover the total cost of providing Standard Service shall be accumulated in a reconciliation account, together with interest applied at the same rate as that set forth for interest on customer deposits, shall be recovered by the Company through a uniform cents per kilowatt-hour surcharge applied to the rates for Standard Service, subject to the terms of §I.B(5)(b) of the Settlement Agreement. Any under recovery that remains after the February 28, 2005 end of the transition period shall be recovered from all retail delivery service customers through a uniform cents per kilowatt-hour surcharge not to exceed $0.004 per kilowatt-hour commencing on January 1, 2010.

Should any balance remain outstanding subsequent to the refund or recovery of over or under collections as described above, the Company shall reflect as an adjustment in the current reconciliation period the amount of the outstanding balance.

For purposes of the above reconciliation, Standard Service revenues shall mean all revenue billed to Standard Service customers through the Standard Service rate for the applicable 12-month reconciliation period. The cost of providing Standard Service shall mean the cost incurred by the Company in providing Standard Service, which shall include, but not be limited to, payments to Standard Service suppliers for procuring Standard Service power, compliance with current or future statutes, rules or regulations which confer an obligation upon the Company and that is directly related to the Company's requirement to provide Standard Service, and any other costs reasonably incurred as a result of the Company's provision of Standard Service.

Each adjustment of the prices under the Company's applicable rates shall be in accordance with a notice filed with the Department of Telecommunications and Energy (the Department) setting forth the amount of the increase or decrease and the new Standard Service Cost Adjustment amount. The notice shall further specify the effective date of such adjustment, which shall not be earlier than thirty days after the filing of the notice, or such other date as the Department my authorize.

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
STANDARD SERVICE COST ADJUSTMENT PROVISION

The operation of this Standard Service Cost Adjustment clause is subject to Chapter 164 of the General Laws.

Effective: ~~March 1, 1998~~January 1, 2003

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
DEFAULT SERVICE ADJUSTMENT PROVISION

The prices for Retail Delivery Service contained in all the rates of the Company are subject to adjustment to reflect the costs incurred by the Company in arranging Default Service, which costs are not recovered from Customers through the Default Service rate charged to Default Service Customers.

On an annual basis, the Company shall reconcile its total cost of providing Default Service supply against its total Default Service revenue, and the excess or deficiency shall be refunded to, or collected from, all of the Company's retail delivery service customers on a per kilowatt-hour basis over the following 12 months, with interest. Such per kWh charge or credit is referred to as the Default Service Adjustment Factor.

For purposes of the above reconciliation, total Default Service revenues shall mean all revenue billed by the Company to Default Service customers through the Default Service rates for the applicable 12-month reconciliation period. The cost of providing Default Service shall mean the cost incurred by the Company in providing Default Service, which shall include, but not be limited to, payments to Default Service suppliers for procuring Default Service power, compliance with current or future statutes, rules or regulations which confer an obligation upon the Company and that is directly related to the Company's requirement to provide Default Service, and any other costs reasonably incurred as a result of the Company's provision of Default Service.

Should any balance remain outstanding subsequent to the refund or recovery of over or under collections as described above, the Company shall reflect as an adjustment in the current reconciliation period the amount of the outstanding balance.

Each adjustment of the prices under the Company's applicable rates shall be in accordance with a notice filed with the Department of Telecommunications and Energy (the Department) setting forth the amount of the increase or decrease and the new Default Service Adjustment amount. The notice shall further specify the effective date of such adjustment, which shall not be earlier than thirty days after the filing of the notice, or such other date as the Department my authorize.

This provision is applicable to all Retail Delivery Service rates of the Company. The operation of this Default Service Adjustment clause is subject to Chapter 164 of the General Laws.

Effective January 1, 2003

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
DEFAULT SERVICE ADJUSTMENT PROVISION

The prices for Retail Delivery Service contained in all the rates of the Company are subject to adjustment to reflect the ~~power purchase~~ costs incurred by the Company in arranging Default Service, which costs are not recovered from Customers through the Default Service rate charged to Default Service Customers.

On an annual basis, the Company shall reconcile its total cost of ~~purchased power for~~providing Default Service supply against its total ~~d~~Default ~~s~~Service revenue~~.~~, and the excess or deficiency shall be refunded to, or collected from, all of the Company's retail delivery service customers on a per kilowatt-hour basis over the following 12 months, with interest. ~~(~~Such per kWh charge or credit is referred to as the Default Service Adjustment ~~Cost Adjustment~~ Factor~~)~~.

For purposes of the above reconciliation, total ~~purchased power~~Default Service revenues shall mean all revenue ~~collected~~billed by the Company to ~~from~~ Default Service customers through the Default Service rates for the applicable 12-~~-~~month reconciliation period ~~together with payments or credits from suppliers~~. The cost of providing Default Service shall mean the cost incurred by the Company in providing Default Service, which shall include, but not be limited to, payments to Default Service suppliers for procuring Default Service power, compliance with current or future statutes, rules or regulations which confer an obligation upon the Company and that is directly related to the Company's requirement to provide Default Service, and any other costs reasonably incurred as a result of the Company's provision of Default Service.

Should any balance remain~~If there is a positive or negative balance in the then current Default Adjustment account~~ outstanding subsequent to the refund or recovery of over or under collections as described above~~from the prior period~~, the Company~~balance~~ shall reflect as an adjustment in the current reconciliation period the amount of the outstanding balance~~be credited against or added to the new reconciliation amount, as appropriate, in establishing the Default Service Cost Adjustment Factor for the new reconciliation period~~.

~~The calculation of the Default Service Cost Adjustment Factor shall be subject to the review and approval of the Department of Telecommunications and Energy.~~Each adjustment of the prices under the Company's applicable rates shall be in accordance with a notice filed with the Department of Telecommunications and Energy (the Department) setting forth the amount of the increase or decrease and the new Default Service Adjustment amount. The notice shall further specify the effective date of such adjustment, which shall not be earlier than thirty days after the filing of the notice, or such other date as the Department my authorize.

This provision is applicable to all Retail Delivery Service rates of the Company. The operation of this Default Service Adjustment clause is subject to Chapter 164 of the General Laws.

Effective ~~March 1, 1998~~January 1, 2003

Exhibit MJH-5

ISO-NE Costs Resulting from SMD

Massachusetts Electric Company
Standard Offer Expense Billed by ISO-NE
Relating to Two Standard Offer Contracts
March 2003 - September 2003

	Total for Period		
	Supplier 1	Supplier 2	Total
Energy Day Ahead	($3,033,514.61)	$0.00	($3,033,514.61)
Energy Real Time	$4,331,929.66	$807,598.76	$5,139,528.42
Regulation	$81,007.90	$5,115.92	$86,123.82
ICAP Load Shifting	($309.96)	($3,086.17)	($3,396.13)
OPRES Real Time	$79,573.37	$456,647.38	$536,220.75
Demand Response	$241.99	$0.00	$241.99
Collect Trans Cost for Repay	$5,277.55	$3,228.82	$8,506.37
Month Off-Peak ARR Credit	($212.09)	($2,087.05)	($2,299.14)
Load Response Monthly Fee	$29.43	$15.56	$44.99
Load Response Monthly Fee	$22.25	$33.38	$55.63
Load Response Monthly Fee	$25.41	$47.07	$72.48
ISO Schedule 3 VM	$0.00	$0.00	$0.00
ISO Schedule 2	$0.00	$0.00	$0.00
Corr Collect Transition	$2,039.97	$0.00	$2,039.97
Class 1 Load Response Field Device	$0.00	($307.98)	($307.98)
Monthly On-Peak ARR Credit	($5,444.44)	($86,952.72)	($92,397.16)
	$1,460,666.43	$1,180,252.97	$2,640,919.40
Withheld from Supplier 1 Bill			
Real Time Energy Charge/Credit	$3,720,950.45		$3,720,950.45
Real Time Congestion Charge/Credit	$59,526.67		$59,526.67
Real Time Loss Charge/Credit	$495,893.01		$495,893.01
Real Time Marginal Loss Rev Alloc	$235.32		$235.32
External Inadvertent Cost Distribution	$9,855.33		$9,855.33
Day Ahead Energy Charge/Credit	($3,645,402.29)		($3,645,402.29)
Day Ahead Congestion Charge/Credit	$224,466.59		$224,466.59
Day Ahead Loss Charge/Credit	$387,421.09		$387,421.09
Regulation Charges	$81,275.48		$81,275.48
Real Time Economic Op Reserve Chges	$89,589.18		$89,589.18
Collected Transition Costs for Repay	$5,277.55		$5,277.55
Demand Response	$72.95		$72.95
ICAP Load Shifting	($359.13)		($359.13)
Load Response Monthly Fee	$15.81		$15.81
Collected Transition Cost for Repay-3/03	$11.53		$11.53
ISO Schedule 2 Charges-curr mo est	$11,433.08		$11,433.08
ISO Schedule 3 VM-curr mo est	$7,201.48		$7,201.48
ISO Schedule 2 Charges-1 mo lag	$23,604.72		$23,604.72
ISO Schedule 3 VM-1 mo lag	$23,343.85		$23,343.85
Real Time RMR Charge	$0.00		$0.00
ARR Credit On Peak (goes w/congestion)	$7,138.47		$7,138.47
ARR Credit Off Peak (goes w/congestion)	($719.53)		($719.53)
ICAP Load Shifting	($27.69)		($27.69)
ARR Credits/Charges	($4,339.62)		($4,339.62)
	$1,496,464.30	$0.00	$1,496,464.30
Net Incremental SO Expense	($35,797.87)	$1,180,252.97	$1,144,455.10

Exhibit MJH-6

February 27, 2003 Filing in D.T.E. 97-94

Massachusetts Electric
A **National Grid** Company

Amy G. Rabinowitz
Counsel

February 27, 2003

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

RE: D.T.E. 97-94; Massachusetts Electric Company and Nantucket Electric Company Request for Approval and Corresponding Rate Treatment for Standard Offer Supply Contract Amendment

Dear Secretary Cottrell

Massachusetts Electric Company and Nantucket Electric Company (collectively "Company") hereby request approval of an amendment to the Company's Standard Offer supply contracts ("Original Agreements") with one of its current Standard Offer suppliers (the "Amendment").

Like other supplier contracts executed by the Company, the terms of the proposed Amendment, including the identification of the supplier, are considered proprietary and confidential. Accordingly, I am enclosing a Motion for Confidential Treatment of the Amendment and the Original Agreements. I am providing a copy of the Amendment and Original Agreements to the Hearing Officer in this matter, under separate cover, and am also providing the Hearing Officer with a confidential analysis comparing the costs incurred under this Amendment to other potential alternatives.

By this filing, the Company is requesting approval from the Department to include in its Standard Offer Adjustment Provision the additional costs that would be incurred under the proposed Amendment. Recovery of costs under the proposed Amendment would not require any modification to the Company's presently effective Standard Offer Adjustment Provision. The Company is estimating that the Amendment would result in an increase of $3.2 million per year over the price that the Company presently pays under the Original Agreements with this supplier based on calendar year 2002 Standard Offer loads. This equates to an increase in typical 500 kWh residential bills of 25 cents per month.. It is important to note at the outset that, in the absence of this Amendment, the Company and its customers may incur even greater costs.

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Background

The Amendment was executed on January 27, 2003 with a pre-existing Standard Offer supplier that provides a portion of the Standard Offer power requirements for the former Eastern Edison Company and its former Rhode Island affiliates (the "EUA Companies"). As successor in interest to Eastern Edison by reason of merger on May 1, 2000, the Company purchases Standard Offer supplies under the terms of the Original Agreements executed in 1998.

The Original Agreements contain unique language not found in any of the Company's other Standard Offer agreements. The Company refers the Department to the terms of the Agreement and, in particular, Article 3, paragraphs 2 and 5, and the defined terms therein. Under the present NEPOOL pricing scheme, costs to both the supplier and the Company were clearly delineated under these provisions. However, with the implementation of ISO's Standard Market Design ("SMD") and locational marginal pricing ("LMP") scheduled to go into effect on March 1, 2003, the Company and the supplier had different interpretations of their respective obligations under the Original Agreements. Under the supplier's interpretation, in reliance on language unique to this supplier's agreement, the supplier would have flexibility to deliver to any point on the NEPOOL PTF System without incurring any additional congestion cost, thereby leaving the Company an its customers to bear the incremental congestion cost burden. As discussed below, the company is unable at this time to predict, with certainty, the magnitude of congestion costs to which it might have been exposed were the agreement to be interpreted to permit the supplier to have delivery point flexibility.

It is important to note that while transmission delivery points in Massachusetts are not expected to incur any significant congestion costs, they are also not likely to be the lowest cost delivery points or "nodes" on the NEPOOL PTF system. Thus, absent the amendments, a supplier may have sought to deliver the power at the lowest cost delivery points available to it anywhere within New England. As the Company's analysis shows, it is possible that, absent the amendments, the supplier might seek to deliver to a node in Massachusetts that has a lower energy clearing price than the zonal price and thus congestion costs could be incurred even if power is delivered in state. In addition, the NEPOOL rules allow the supplier to specify the delivery location after the dispatch day. Thus, if the contracts were construed such that the Company must bear congestion costs, the Company would also be unable to effectively mitigate its congestion costs exposure. Because both parties recognized the differing interpretations, and the supplier could better mitigate congestion cost exposure, the parties negotiated the proposed amendments. The Company believes that these Amendments mitigate the uncertainty and the litigation risk in a least-cost manner and, accordingly, the Amendments are in the best interests of customers.

The Proposed Amendment

Under the proposed Amendment, the Company will pay an additional fee to the supplier, fixed on a per-kWh basis, in exchange for the supplier's agreement to deliver Standard Offer supplies directly to the Company's load centers. See Paragraphs 3 and 5 of the Amendment. The supplier would bear any congestion cost required to meet its delivery obligation. This Amendment will not become effective unless Department approval is first received to include these costs as part of the overall supply costs included in the Company's Standard Offer Adjustment Provision. Finally, if Department approval is not received by June 27, 2003, the Amendment will terminate by its own terms.

Although the Company has the option to continue service under the Original Agreements, we believe that the proposed Amendment is in the public interest for two primary reasons. First, the Amendment caps customer exposure to upside congestion cost risk because the fee charged is fixed on a per kWh basis and cannot increase during the term of the Original Agreements (through 2009, however, the Standard Offer loads for Eastern Edison terminate at midnight on February 28, 2005). As mentioned above, it also puts the cost risk on the party most able to mitigate that risk. Moreover, it does so while mitigating the litigation risk.

Second, the supplier has agreed to bear the congestion cost risk at a reasonable price based on the Company's analysis. Although an LMP system has not yet been implemented, indicative locational marginal prices recently published by the ISO show the expected price difference between over 40 locations in New England, including the SEMA zone, where the applicable standard offer loads are located, is well in excess of the cost proposed to be paid to the supplier under the Amendment. This reasoning is also supported by independent price quotes sought by the Company and its affiliates from other independent suppliers. The available price quotes were at a price that was more than double the amount being sought by the Company's supplier. A summary of these analyses is provided in confidential attachments included with this filing.

Requested Approval and Timing

Although the Original Agreements were subject to the jurisdiction of the Federal Energy Regulatory Commission, the Company and its supplier have agreed that the Amendment will not become effective unless the Company receives approval from the Department to include its costs as part of the Company's Standard Service Cost Adjustment Provision. Accordingly, the Company requests Department approval to recover its costs from this Amendment. If the Department does not approve the Amendment, the Company would be at risk of incurring congestions costs under the Original Agreements that would be recoverable as discussed above. Accordingly, the Company believes that this is not a matter of whether cost recovery is available under the Standard Offer Adjustment Provision, but rather on what basis it is preferable to incur the additional costs. As stated above, the terms of the Amendment require Department approval by June 27, 2003, and the Company respectfully requests Department action by that time.

Conclusion

For the reasons discussed above, the Company respectfully requests Commission approval to include the costs set forth in the enclosed Amendment as part of its Standard Offer Adjustment Provision. We stand ready to supply any additional information the Commission may need in support of this request.

Thank you for your attention to our filing.

Very truly yours,

Amy G. Rabinowitz

Amy G. Rabinowitz

cc: Service List

Exhibit MJH-7

Congestion Costs

Massachusetts Electric Company
Nantucket Electric Company
Congestion Costs
Resulting from Proposed Contract Amendment
March 2003 to Present

Service Month	Congestion Costs
March 2003	$252,012.33
April 2003	$229,647.38
May 2003	$225,774.08
June 2003	$250,720.27
July 2003	$308,643.97
August 2003	$322,826.24
September 2003	$243,367.62
	$1,832,991.89

Source: Monthly Standard Offer Bill, kWh purchased x proposed cost of 0.300¢ per kWh